Controls on the Production Performance of fip3 of the North West Hutton Field, UK North Sea

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Abstract

The North West Hutton Field was discovered in 1975 and is located in Block 211/27 in the East Shetland Basin, Northern North Sea around 80 miles NE of Shetland. It is a large oil field in the Brent Group, covering an area of 13440 acres and has a history of complex and variable well performance, significantly worse than the adjacent up dip Hutton field, despite both having the same Brent Group paralic sandstone reservoirs. North West Hutton was reported to contain 1157 mmBBL oil in place in 1983 and reserves were estimated at 273 mmBBL. It had initially high flow rates which rapidly declined, along with pressure. A water injection programme was implemented, despite this the recovery factor was only around 10%. This study focuses on fip3, otherwise known as the Eastern Sector of North West Hutton, where 12 production wells have been drilled, 3 of which were converted to water injection wells.

The study aims to determine controls on both instantaneous well rate and overall ultimate recovery per well in terms of reservoir architecture, reservoir quality and faulting in fip3. The study used a combination of wireline log and core data coupled with oil production, water production and water injection data on a per-well basis to evaluate field performance.

Laterally extensive and sheet like reservoir architecture such as the valley fill of the Etive Formation were indicated to have been flooded early on in the field's production and the oil swept due to stratigraphic connectivity between wells. Water injection support was ineffective at sweeping sands above and below these. The rapid decline of oil rate was attributed to complex faulting, compartmentalisation and the highly permeable, but heterogenous, thin and poorly connected, fluvial channel sandbodies in the Ness Formation being quickly drained. This study has identified likely remaining oil in these sandbodies, particularly in compartmentalised areas, such as the west of fip3. There may be potential for redevelopment by focusing on these sandbodies in similarly compartmentalised reservoirs of a paralic nature which also suffered rapidly declining pressures. Existing reserves may be accessed using newer tried and tested technology which was not available or not applied in the original development. Tactics such as horizontal drilling or dramatically increasing the water oil ratio (WOR) should be addressed. Controls on the production performance of wells in fip3 were timing (earlier wells performed better due to higher pressures, oil not yet having been swept and had fewer operational issues that develop with time), rock quality (controlled by burial depth and facies), compartmentalisation and sandbody connectivity, pressure support, well spacing and operational issues. Many wells had poor well spacing in that they were drilled into existing flood fronts or too close to existing wells, restricting the expected ultimate recovery per producer. The study has indicated the potential for redevelopment in the south of fip3, where A14 previously had good performance and received good pressure support.

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List of abbreviations

CPI- Computer processed image

FIP3- fipnum3- Fluid In Place (Region Number 3) in ECLIPSE (Eastern Sector of NW Hutton)

GOR- gas oil ratio

GR- gamma ray

HCS- hummocky cross stratified

K- permeability

MD- measured depth

MMBBLS- millions of barrels of oil
CB- cross bedding

MNS- Mid Ness Shale

N:G- net to gross

NW- north west

ODT- oil down to

OWC- oil water contact

PLT- production logging tool

RFT- repeat formation tester

STOIIP- stock tank oil in place

TVDSS- true vertical depth subsea

Vshal- Volume of shale

WHP- wellhead pressure

WOR- water oil rate

WUT- water up to

Φ= porosity

Declaration

I declare that this thesis, presented for the degree of Master by research in Earth Science at Durham University, is the result of my own original research and has not been previously submitted to Durham University or any other institution.

Acknowledgements

First and foremost, I would like to thank my supervisors Jon Gluyas and Matt Mulcahy for their guidance, support and knowledge this year. Thank you also to Jeb and Faz from Bridge Petroleum for their data and help.

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1 Introduction and Literature Review

1.1 Aims and Overview

The key aims of the study are to

- Determine the controls on both instantaneous well rate and overall ultimate recovery per well in fip3 (also known as the Eastern Lobe), a sector of the NW Hutton field.
- Identify the high quality reservoir bodies in fip3, and to interpret their geometries and connectivity between wells
- Determine the nature of heterogeneities within the reservoir bodies
- Assess the effectivity and impact of pressure support
- Identify remaining potential in fip3

NW Hutton is in the northern North Sea, in the Viking Graben, Block 211/27. It has had 14 wells drilled; A03 (failed), A03Z, A08Z, A14, A15, A16, A21, A29, A32, A37, A40 (failed), A41, A41z and A48, and is considered to have potential for additional oil production by current operators Bridge Petroleum.

NW Hutton was discovered in 1975 and ceased production in 2002. It has a history of complex and variable well performance, significantly worse than the adjacent up dip Hutton field, despite both having the same Brent Group paralic sandstone reservoirs. NW Hutton had high initial flow rates which rapidly declined, and pressure was depleted very quickly. A water injection programme was used, despite this, the recovery factor was only around 10%. The poor performance of NW Hutton was attributed at various times to intensive faulting and/or poor reservoir quality. The sandstones of NW Hutton are more deeply buried than those at Hutton and the porosity and permeability are lower. However, it is not clear which of these characteristics was the most important in determining how the two fields performed.
Controls on the dynamic performance of fip3 wells are currently hypothesised to be a combination of geology, faulting and operational challenges.

A successful understanding of field performance could assist Bridge Petroleum in their plan to reactivate parts of NW Hutton that were not fully developed. The study uses a combination of wireline log and core data coupled with oil production, water production and water injection data on a per-well basis to evaluate field performance.

Production data were analysed on a well by well basis and compared spatially and temporally to gain an understanding of field performance. By examining and comparing wells in close proximity, marked changes in reservoir quality can be observed, and controls on this interpreted.

The study investigates controls on rock quality, compartmentalisation, and what the plumbing system and reservoir architecture within fip3 is like. An understanding of facies and depth/ temperature control on rock quality is required. Localised and more detailed sedimentary modelling is required, particularly of the Ness Formation to predict reservoir geometries.
The effect of the water injection programme, which layers fluid travels through and where, and the effect faulting has on this will be studied to assess unswept areas or layers of fip3.

1.2 Regional & Tectonic Setting

The North West Hutton Field is situated in Block 211/27 of the UK North Sea in the East Shetland Basin, around 80 miles NE of Shetland (Figure 1). It is a large field in the Brent group, a major North Sea exploration target, and was discovered in 1975. The field covers an area of 13440 acres and contained, at discovery, approximately 1 billion bbl oil initially in place (STOIIP), of which 135 million bbl of oil has been produced by cessation of production (Gluyas et al, 2020). The STOIIP of fip3 has been calculated at 176 mmBBLs (Data provided by Bridge Petroleum Ltd).

North West Hutton is geologically part of the same single oil field as the up dip Hutton field (discovered in 1972) (Figure 1), and Q- West (discovered in 1994), an informally defined region between the two fields. Legally, Hutton and North West Hutton are defined as separate entities. Since 2009 the southern, undeveloped extension of North West Hutton was informally named Darwin under Fairfield’s ownership (Gluyas et al, 2020). The present operators Bridge Petroleum refer to the area as a whole as Greater Galapagos.

The hydrocarbons of North West Hutton are comprised of a low-GOR crude oil, with an average of 37 API gravity (Scotchman 1989). NW Hutton Eastern Block has a reported GOR of 600 SCF/BBL (standard cubic feet per barrel) and a formation volume factor of 1.38 (Johnes and Gauer 1991). The reservoir is the Brent Group, approximately 300m thick and mostly complete over the East Shetland Basin, with occasionally missing or thin over tilted fault block crests (Richards 1992).

NW Hutton provides some of the deepest oil production from the Brent Group (Figure 2), lying at an average depth of 12000 ft subsea (Scotchman 1989). The hydrocarbons are trapped in a complex tilted fault block structure dipping SW (Figure 2), of the North Viking Graben. The shales of the Heather and Kimmeridge and Clay formations drape the structure and are unconformably overlain by Lower Cretaceous marls and shales. The adjacent Hutton oilfield is up dip at the crest of the major tilted fault block system. Geological history and structural development of the North Viking Graben and its control on the development is well established (Yielding 1992).

The main productive area of the field is divided into four main fault blocks bound by NE-SW trending sealing faults, where the Middle and Eastern sectors have had the most wells drilled (Figure 3). The area focused on in this study is fip3, also known as the Eastern sector, with the Brent reservoir section at depths 11571.7- -11168.7 ft TVDSS (true vertical depth in feet sub-sea level).

The oil-water contact (OWC) levels vary between fault blocks (Figure 4). The OWC is much deeper in the west (13250ft TVDSS) than in the east (11850ft TVDSS). The Eastern and Central sectors have common contact at 11930ft TVDSS. The bubble point in the east is 1890psi, compared with 2520 psi in the west (Gluyas et al, 2020).

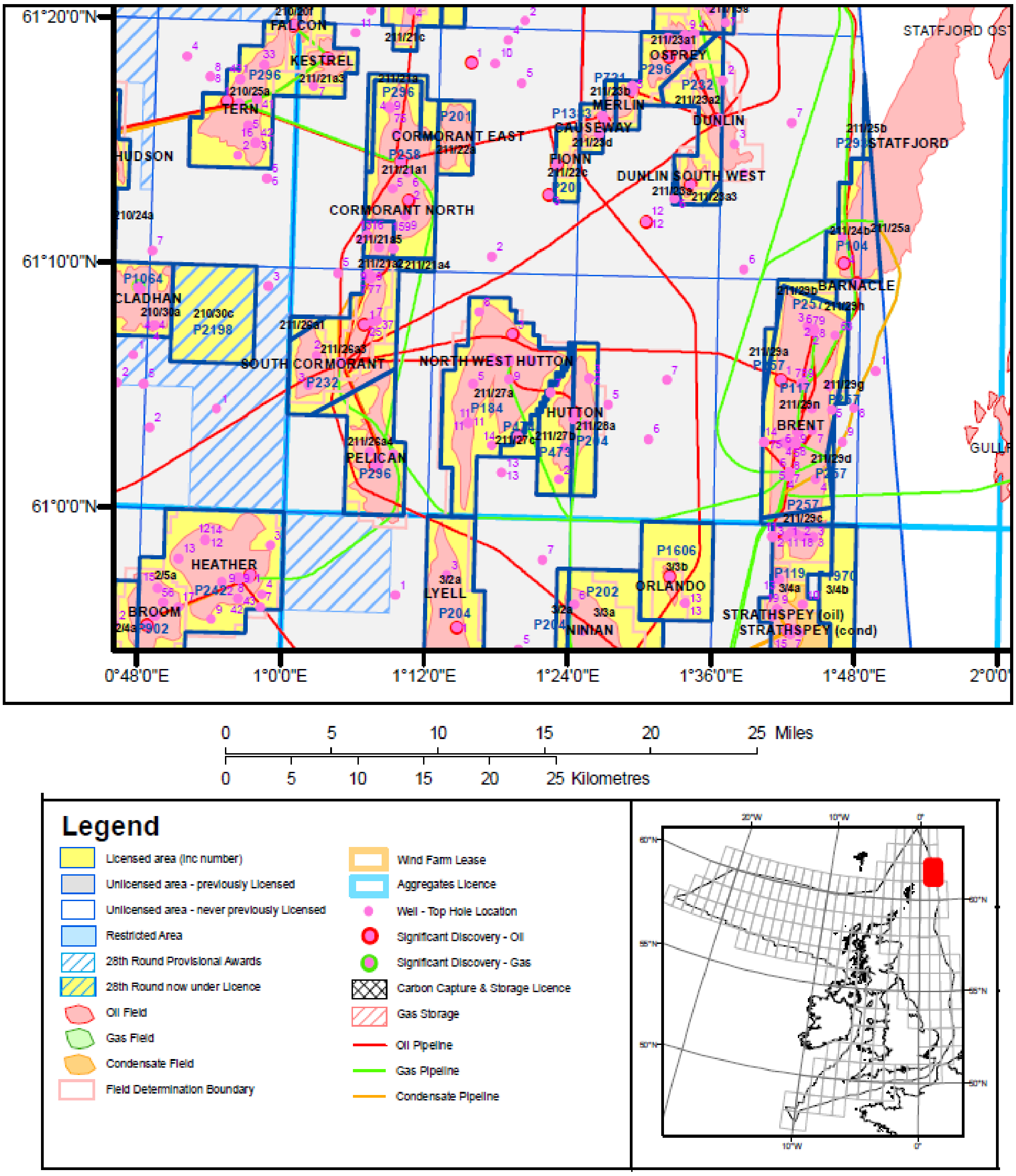

Figure 1- Licencing areas of fields in Northern North Sea (image provided by Bridge Petroleum Ltd)

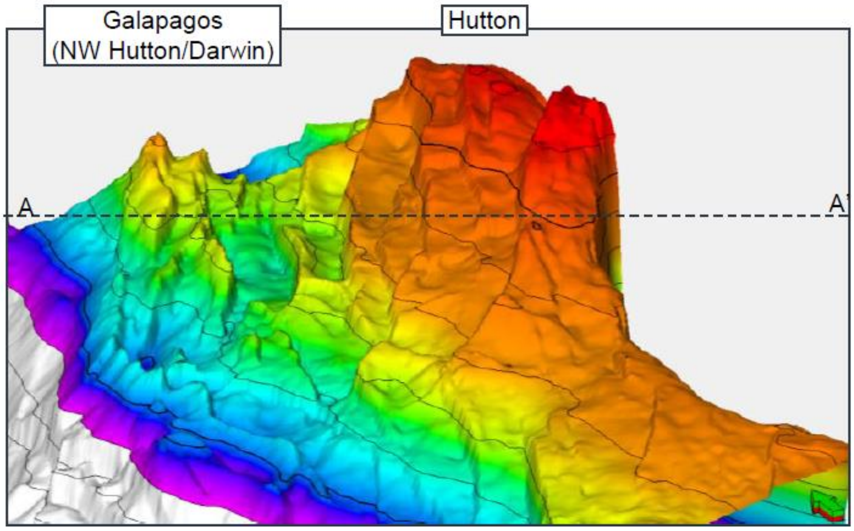

Figure 2- Structural setting of NW Hutton (vertical exaggeration X5) (image provided by Bridge Petroleum Ltd)

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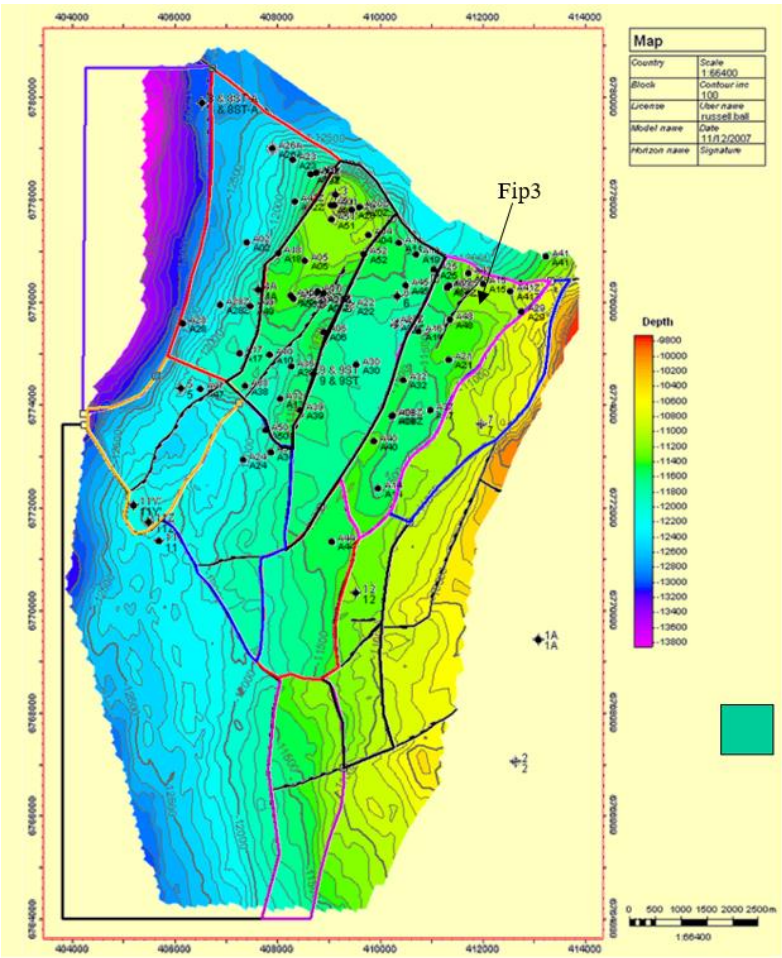


Figure 3- Main segments of NW Hutton. Fip3 labelled (Fairfield 2008)

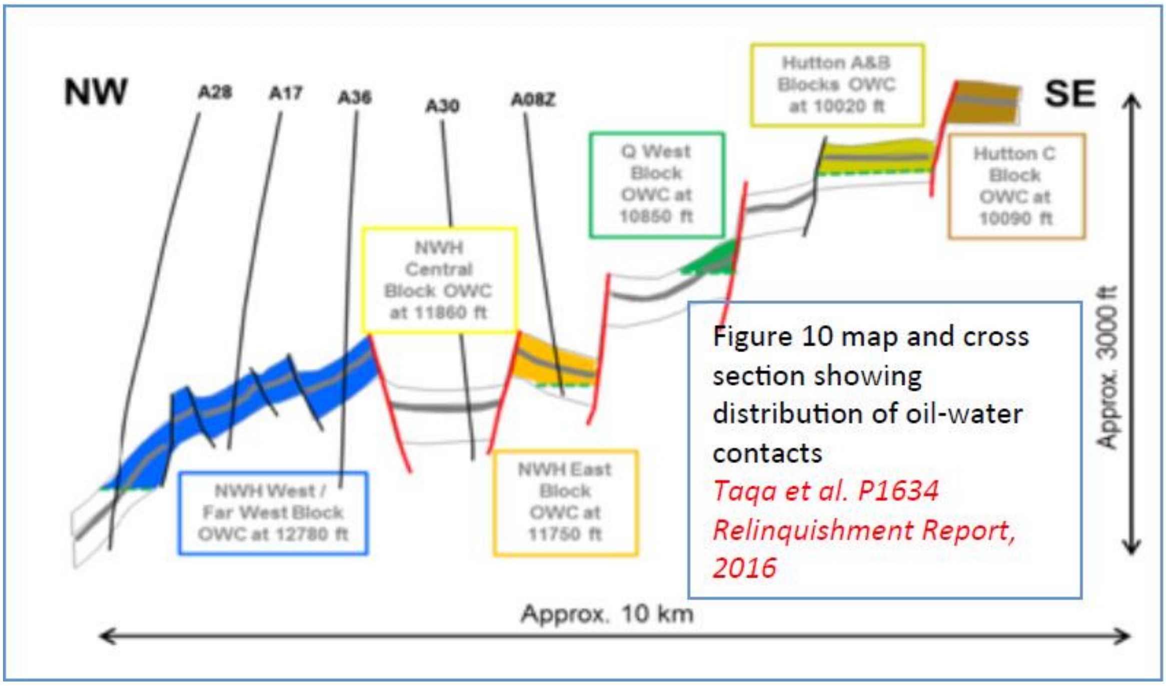


Figure 4- Cross section showing fip3 (eastern block) OWC and Graben structure (TAQA 2016)

1.3 Faults in fip3

1.3.1 Fault Trends

The faults define the main terraces in North West Hutton, as well as different OWCs (Figure 4). Fault terraces are sealed, however within terraces the system is generally open. Minor faults within terraces usually act as either baffles or points of cross flow (Bridge 2018). This may create resultant tortuosity that can create good sweep paths for injectors to producers. The field is both horizontally and vertically compartmentalised by heavy faulting as well as sealing mudstones.

The primary fault trend in North West Hutton and fip3 is NE-SW (Figure 6), including the Hutton and Cormorant South Fault (Yielding 2011). These are interpreted to be formed as the result of reactivation of existing Triassic Basement faults (Scotchman 1989).

The secondary observed trend is NW- SE, including the Pelican Fault. Where the two sets interact, it is inferred that the NW-SE fault planes were later initiated, cross cutting the pre-existing NE-SW set.

The NW Hutton northern bounding fault is tentatively interpreted as a transfer fault. Both trends show dips in both directions, although the dominating NW dipping faults tend to be steeper than the SE dipping faults (Figure 6). Different areas of North West Hutton are dominated by faults of a common dip direction, with complex fault interactions where dip domains overlap. The dip azimuth in fip3 is 290-330° (Yielding 2011).

The faults mapped at the top Brent level were active during the Late Jurassic, interpreted to have initiated before the bulk rotation of the Hutton block via its bounding faults. (Yielding, 2011). SE dipping faults in NW Hutton similarly display Triassic growth and the Hutton Boundary Fault is interpreted as Jurassic. The Pelican Boundary Fault and associated faults display no evidence of Triassic movement; therefore the set is interpreted as related to late Jurassic extension (Yielding, 2011).

The fault interpretations of fip3 for this study are provided by Bridge Petroleum Ltd, based on edge detection volumes (dip of max similarity) (Figure 5).

1.3.2 Seismic Dataset

NW Hutton was discovered following interpretation of a 2D seismic data set and identification of a closed structure. Several further surveys were undertaken between 1975-1978. There are multiple seismic data datasets, revaluated and improving with time. Reprocessing results in better fault plane resolution, improved signal to noise rations, allowing increased confidence in structural mapping in faulted areas.

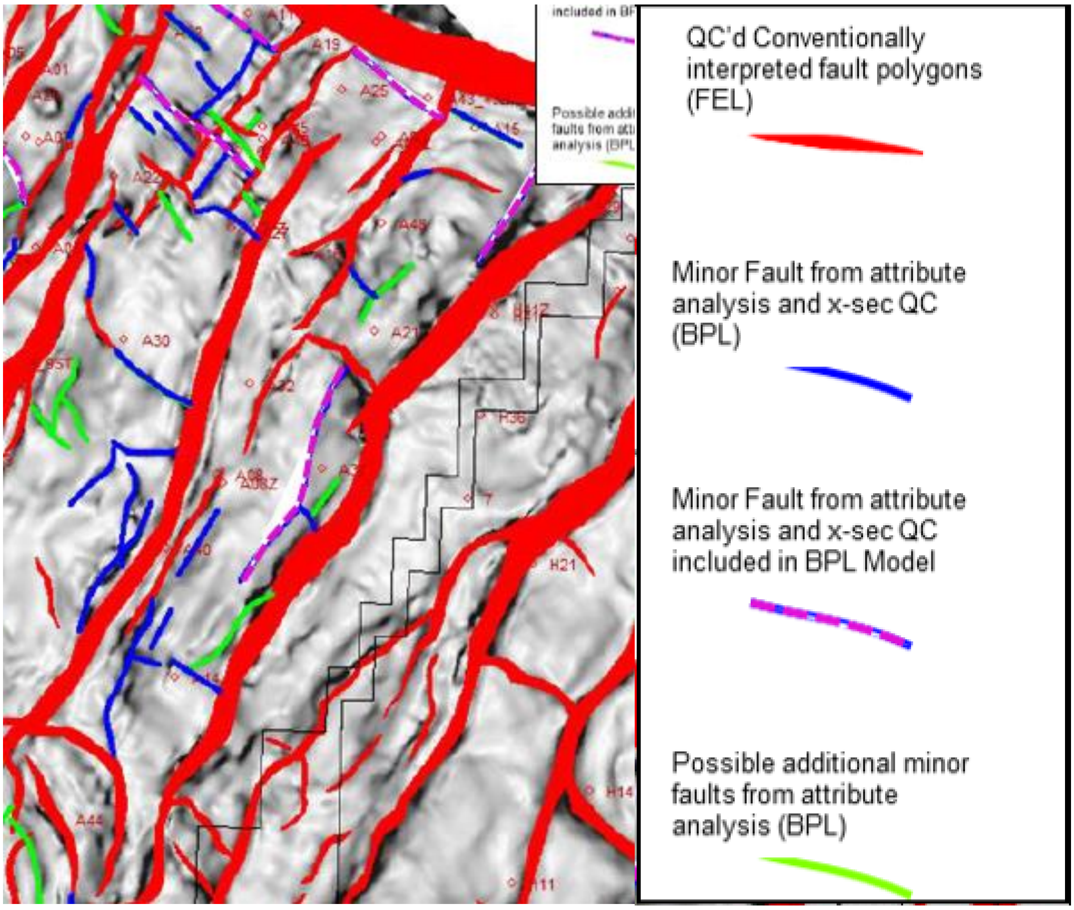


Figure 5- Faults derived from Fairfield (provided by Bridge Petroleum Ltd)

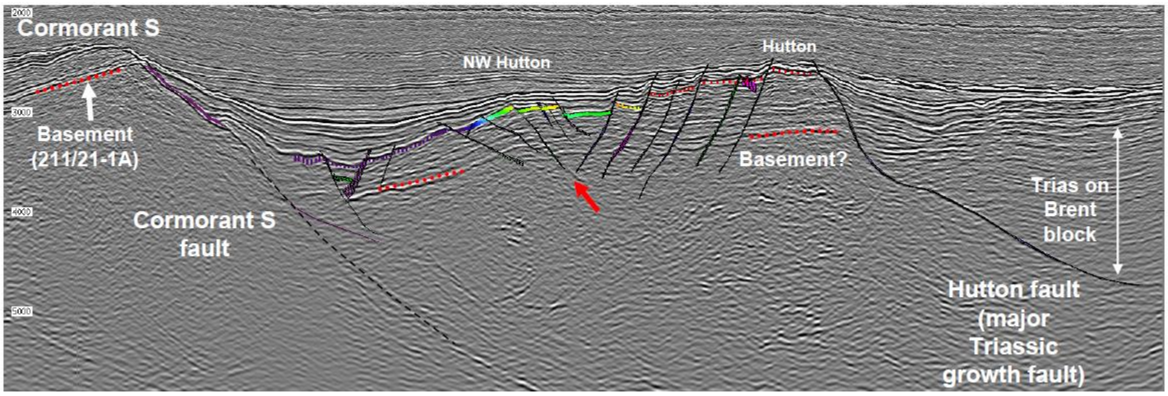


Figure 6- Interpreted major fault terraces off seismic section (Yielding, 2011). Shows steeper NW dipping faults and SE dipping faults, showing Triassic growth

1.4 Wells in fip3

14 wells were drilled, 2 of which failed (Table 1). A08Z, A16 and A21 were converted to water injection wells. Well locations are displayed in Figure 7. Just four wells in fip3 (A08Z, A14, A15, A37) have been cored.

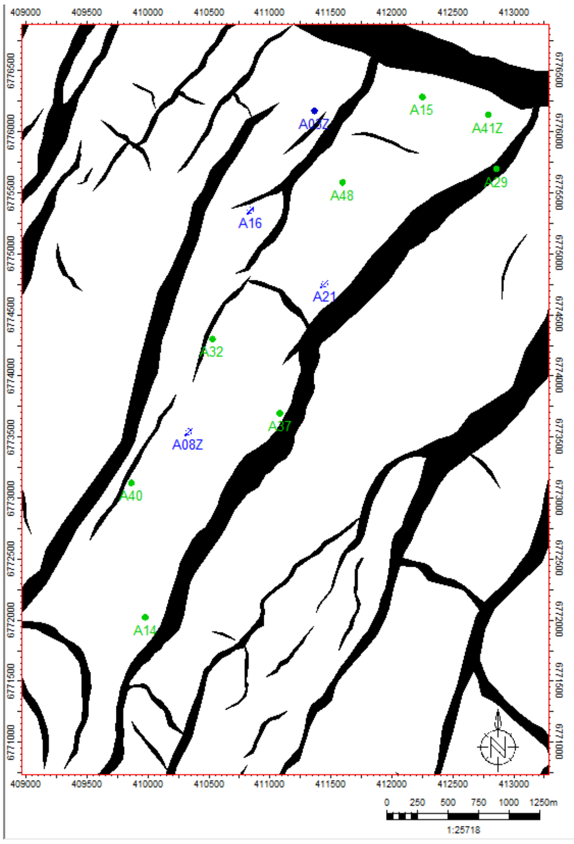


Figure 7- Base map of fip3 showing well locations (water injectors blue, producers green), and major faults

DTI Well Name	**Spud Date**	**TD MD**	**Top Brent Comp Log (SS)**	**Top Brent (SS)**	**Production Start-Up Date**	**Cum Oil Prod**	**Initial Oil Rate**	**Last Day of Prod**	**Reason for Shut-in**
A03	15/06/1980	15085	11399	11402					FAILED
A03Z	21/05/1983	15273	11392		01/07/1983	**2.11**	10884.00	01/12/1992	Thought to be a damage problem
A08Z		16262	11461	11447	01/11/1983	**6.54**	13949.00	01/03/1991	Hole full of fish!
A14	08/10/1983	19370	11565	11534	15/07/1984	**7.27**	6318.39	01/06/1999	Good Producer
A15	13/03/1984	17180	11074	11118	01/06/1984	**10.20**	15499.12	01/01/1989	Good Producer shut-in due to excessive pressures on the surface casing
A16	29/05/1984	14691	11525	11540	01/07/1984	**0.44**	4872.23	01/03/1985	Conv to WI in Dec 94 (in Sept 84 it was still doing 4000BOPD)
A21	02/12/1984	16136	11415	11434	11/02/1985	**0.12**	2538.37	01/03/1985	Conv to WI. Last test was 4300BOPD no WC
A29	24/11/1985	18622	10973	11018	02/02/1986	**5.26**	4965.71	01/05/1999	Good well - without GL owing to annulus comm problems.
A32	24/08/1987	15720	11446	11443	18/10/1987	**1.11**	1605.52	01/05/1999	OK Producer
A37	27/06/1988	17400	11571	11572	02/09/1988	**0.51**	1923.94	01/01/1994	Failed cleanout stopped production
A40	24/06/1989	16885	11358	11359	01/10/1989	**0.96**	2371.64	01/08/1993	Good rates at first, high water presence - severe scaling.
A41	19/08/1989	21020	11540	11540					FAILED
A41Z	02/12/1990	19300	11012	11015	15/03/1991	**2.99**	10518.36	01/06/1999	Good well. Area partially depleted.
A48	25/02/1991	16730	11272	11271	09/05/1991	**0.07**	2075.14	01/04/1993	High water cut - Shut-in due to large fish
Count	**14**				**total**	**37.58**	6460.12		

Table 1-Fip3 wells dates, depths, cumulative oil, initial oil rate and reason for shut in (Bridge Petroleum)

1.5 Stratigraphy

Sedimentology of the Brent Group (Figure 8) has been studied from field scale to regional. Many early studies were based on lithostratigraphy (Richards 1992) or broad scale time significant units (Mitchener et al 1992), however more recent studies have focused on high resolution sequence stratigraphy (Flint et al, 1998).

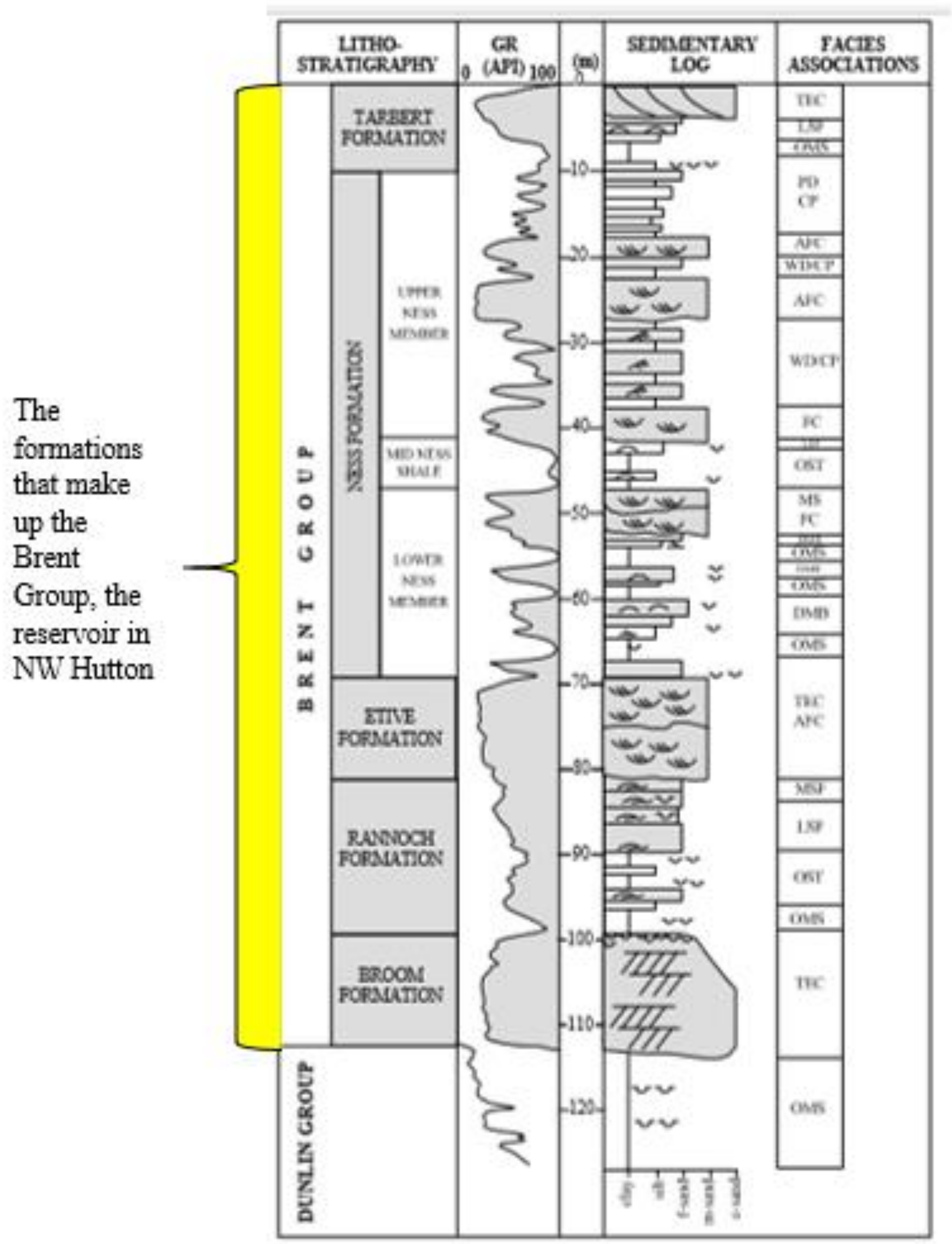


Figure 8- Stratigraphic column of the Brent Group (Flint, 1998)

1.5.1 Lithostratigraphy

The Brent Group is the reservoir in NW Hutton and has been studied in vast detail, resulting in many controversies regarding its age, nature and palaeographic evolution. However, the lithostratigraphy is widely accepted, where the fivefold subdivision of the Group into the Broom (or the equivalent Oseberg Formation in Norwegian waters), Rannoch, Etive, Ness and Tarbert formations (Figure 8) is used in most literature. The subdivision was first recognised by Bowen (1975) and modified and formalised by Deegan & Scull (1977). Although commonly accepted, a few authors, including Dundas (2014) have found it to restrict important lithological and variation within the lithostratigraphic units. Enyon (1981) proposed considering the Brent Group in terms of five depositional units named Basal Sand, Bajocian Delta Lobe, Bajocian-Bathonian marine transgression, Lower Bathonian Delta Lobe and Upper Bathonian Delta Lobe. However, most authors stick with the Deegan & Scull (1977) terminology. In studying the northern limit of delta progradation in the East Shetland Basin, Brown & Richards (1989) found limitations in existing Brent Group lithostratigraphy where the Ness Formation is currently absent and massive sandstones more similar to the Etive Formation are present in the stratigraphic interval instead. The Ness Formation can also be difficult to distinguish from Etive channels. Deegan & Scull (1977) defined the Ness- Tarbert boundary at the top of the uppermost shale unit on well logs, which has resulted in difficulties in identifying based on this as erosion may cut into the Ness Formation and the Tarbert Formation is locally heterolithic. Core analysis may assist identification of the coarse-grained transgressive lag deposits above ravinement surfaces and/or marine bioturbation indicating the base of the Tarbert Formation.

Thickness variations of the Broom, Rannoch, Etive and Ness Formations occur due to deposition on varyingly subsiding fault blocks, and later erosion particularly with the Ness Formation (Brown et al, 1987).

Companies often use field specific stratigraphic schemes to subdivide the reservoirs as the original subdivision may constrain depositional system correlation. Bridge Petroleum subdivides the Ness Formation into sandstones and shales Upper Ness A-G and Lower Ness A-G.

1.5.2 Sedimentology

The Brent Group has been studied in vast detail due to its huge economic importance, with over 200 papers having been published detailing its stratigraphy, structure, sedimentology and oilfield geology. Considerable controversy over almost all aspects exists, often over the age of units or regional architecture of its depositional system.

The formations that make up the Brent Group are described below.

1.5.2.1 Broom Formation

The Broom, also known as the Basal sand unit, rests on the sequence boundary of the Lower Jurassic Dunlin Group mudstones. It is a coarse-grained sandstone with mud draped cross beds. There is marine bioturbation at the base and top, and some terrestrial coal debris is present (Flint et al 1998).

It is interpreted as a lowstand to transgressive systems tract tidal- estuarine complex (Flint et al 1998) as part of the easterly prograding, shallow marine fan delta system (Brown 1987). Shallow to deep water interpretations have also been documented, however the fan interpretation is more popular in recent studies.

1.5.2.2 Rannoch Formation

The Rannoch Formation is a hummocky cross stratified, micaceous sandstone with interbedded sandy heteroliths, that overlays the 1m Rannoch shale at the base (Flint et al 1998). Associated bioturbated sandstones represent periods of fair weather reworking. It is dominated by low angle cross stratification (Richards and Brown 1986).

Drill cores display four facies Richards & Brown (1986):

1. Heterolithic beds- Interpreted as an offshore to shoreface transition deposit with thin storm-emplaced sandstone beds

2. Laminated and hummocky cross stratified (HCS) micaceous sandstone.

The remaining facies (below) are the products of shoreface deposition under storm conditions of varying intensities.

3. Indistinctly laminated micaceous sandstone

4. Structureless sandstone

The Rannoch and overlying Etive Formation are occasionally interbedded and considered together in terms of a single genetic package, largely absent from NW Hutton. The Rannoch and Etive Formations thicken to the northeast in the UK Sector. Maximum progradation occurs at the northern edge of the East Shetland Basin (Eynon 1981; Brown & Richards 1987).

The Rannoch Formation in NW Hutton is typical of elsewhere in the Brent Group, and it is interpreted as a widespread, storm-dominated, offshore to shoreface regressive sequence (Richards &Brown (1986). Stratigraphic position of the Rannoch Formation, as well as other structures recorded in the formation (basal scours to beds, bioturbated bed tops and wave ripples) support the interpretation as a shoreface storm deposit. Associated above formations display evidence of storm influences during deposition, such as the basal part of the Ness Formation.

Overlying the Broom Formation is the thick regressive-transgressive clastic wedge of the Rannoch and Etive Formations. It is interpreted as a deltaic sequence prograding NE-wards into the Shetland Basin from the Shetland Platform (Richards et al. 1988).

1.5.2.3 Etive Formation

The Etive Formation is comprised of medium to coarse grained, channelized and cross bedded sandstones, abruptly overlying or interbedded with the Rannoch Formation. Grain size fines up, with basal lags of intraformational clasts and coarser grains of sand (Ichron, 2010). Localised transition to aggradational shoreface sandstones may be present (Scotchman, 1990). The upper Etive Formation contains low abundance, low diversity trace fossil assemblage, trough and planar cross bedding and coaly debris (Flint et al 1998). It is a dominantly fine to medium sandstone with ~6% clay content, clay drapes and paired drapes. It also has a tidal deposition and marine trace fossil assemblage (Ichron, 2010). It is less variable than the Ness Formation and is a thicker sandstone body.

In the Hutton and NW Hutton fields, the Etive Formation displays a thickness transition and thins from 100ft of shoreface deposits in the south-west to around 40ft of fluvial dominated in the north-east of the field (Richards and Brown 1986). The Etive and Rannoch Formations thicknesses negatively correlate, resulting in a generally consistent overall Etive/ Rannoch thickness fieldwide (Gluyas et al, 2020).

The Etive Formation is interpreted as a multilayer fluvial to estuarine channelized system, interpreted as incised valley fills, representing lowstand and early transgressive systems tracts (Flint et al 1998). Channelized fluvial deposition, named as a Distributary Channel facies association (Ichron 2010, Scotchman 1990) occurs in all fip3 wells except A21 and A48. The channels are interpreted to be major channelized tidal inlets that link back barrier and open marine areas (Flint et al 1998). These are laterally separated by interfluve areas are also interpreted (interpreted in A21 and A48 in fip3 by Flint), where the progradational top of the Rannoch Formation remains. The distribution of incised valleys and interfluves are thought to be similar to the Book Cliffs, Utah, USA (Flint et al 1998).

1.5.2.4 Ness Formation

The Ness Formation is the most important reservoir bearing unit in the Brent Group of NW Hutton. It is up to 160m (525ft) thick. It is the main oil- bearing interval over much of NW Hutton and is interpreted as a lobate fluvial dominated delta (Flint et al 1998). It is made up of coalescing distributary channel, and crevasse-splay sandstones and mouth bar complex’s interposed with fine grained overbank and lagoonal shaley facies (Scotchman 1990). It is a non marine delta plain succession that is interpreted as a high stand systems tract to the Etive sequence boundary (Flint et al 1998). The Ness Formation is consistently the most difficult formation to correlate between wells.

1.6.5.4.1 Lower Ness Member

At the base of the formation is a transgressive lagoonal/ marine shale facies overlain by thick fluvio- deltaic coastal plain sediments (Budding & Inglin, 1981). The basal part of the Ness Formation displays evidence of washover storm sandstones and wave rippled sandstones (Richards & Brown 1986) and has a thin (1-3cm) pebble lag in some NW Hutton wells (Flint et al 1998).

The Lower Ness Member has a weakly progradational trend and is comprised of well organised, coarsening upwards facies associations 3-10m thick. These display current ripples and parallel laminations, consistent with a deltaic mouth bar environment (Flint et al 1998). These are truncated by medium grained fluvial sandstones upwardly evolving into estuarine sandstones and heteroliths. The unit is overall interpreted as a laterally amalgamated fluvial/ estuarine channel complex.

Shales present display marine trace fossils including *Teichichnus*, *Planolites*, and *Chondrites*, these are interpreted to be marine flooding surfaces related to a high frequency base level fall within the overall rising base level trend. These have a large lateral extent, providing vertical permeability stratification (Flint et al 1998).

N:G for the unit is relatively low, at 30-40%, however a high net to gross (N:G) unit, interpreted as a thin transgressive marine sheet sandstone is mappable fieldwide just below the Mid Ness Shale (Flint et al 1998).

1.5.2.4.2 Mid Ness Shale

The Mid Ness Shale subdivides the Ness Formation and is a fieldwide stratigraphic marker and vertical seal. Many thin shales in the Upper and Lower Ness Members also show sealing potential. It has a shaley base, minor fine-grained sandstones with hummock cross stratification. It is interpreted as a transgressive marine mudstone and a basal max flooding surface (Flint et al 1998).

1.5.2.4.3 Upper Ness Member

The Upper Ness Member has a highly complex architecture and is comprised of coarse grained stacked fluvial channels, crevasse splay sandstones and flood plain fines. The base is erosive and coarse grained, and in the majority of wells lies immediately over marine shales, however in places e.g A41Z a partial coarsening upwards mouth bar/ shoreface is preserved under the regionally extensive erosive surface (Flint et al 1998). A unit of high N:G exists immediately above the Mid Ness Shale, interpreted as a tidal shoal facies association (Dundas, 2014).

Fluvial deposits are interpreted to be from low gradient, minor ribbon channel sandstones, and their distribution cannot accurately be predicted or correlated, but are predominantly orientated west-east. The interval of stacked, widespread channels points to a change in drainage orientation and is linked to high-frequency sea level fall (Flint et al 1998).

The member is interpreted as a dominantly well drained floodplain, alternating with times of poor drainage. Accommodation space decreases towards the top Upper Ness Member, resulting in more fluvial amalgamation and connectivity compared to the Lower Ness Member. The sandstones of the Upper Ness Member are more channelized, whereas the Lower Ness Member is predominantly sheet sandstones (Flint et al 1998).

The Upper Ness Member has been subdivided into lower (sand prone) and upper (shale prone) zones (Livera 1989). The lower sand prone zone has a statistically higher net to gross (60+%), indicating a significant degree of lateral connectivity. This is supported by

1. Significant pressure declines observed in NW Hutton development wells within the Upper Ness sandstone (Flint et al 1998)

2. Injection water proven to be able to move long distances through the lower sand prone channels (Flint et al 1998)

The uppermost Ness in NW Hutton is identified by a flooding surface, with a return to shales with marine ichnofabrics.

1.5.2.5 Tarbert Formation

The Tarbert Formation is the uppermost reservoir sandstone unit and is related to a further major sequence boundary. The unit is typically 1-6m thick, with an upward fining from coarse granular base, minor cross bedding and clay drapes at base. A marine shale incursion is present at the base of the Tarbert Formation and is overlain by regressive- marine sheet sandstones. Distributary channel sandstones and mouth bars, crevasse splay lobes, transgressive and marginal marine sandstones and sub-littoral sheet sandstone facies make up the reservoir quality sandstone bodies. Non reservoir facies act primarily as permeability barriers, and include marine claystones, lagoonal deposits and delta-plain overbank sediments (Scotchman 1990).

The formation is interpreted as a marine transgressive unit overlying the lowstand complex (Flint et al 1998).

1.6 Depositional Environment

At a regional scale the depositional model is of a major shoreface and coastal succession (the Rannoch and Etive Formations respectively), overlain by the semi time equivalent shallow lagoonal to delta plain deposits of the Ness Formation, and the final transgressive unit of the Tarbert Formation (Figure 9).

Detailed sequence stratigraphy has shown the studied succession is made up of several transgressive and regressive packages, including higher order events (Flint et al 1998).

The formations are products of northwards progradation of a major wave dominated delta system (Budding and Inglin 1981). Deposition occurred during a post rift, thermal subsidence phase of basin evolution during a minor phase of continued, extensional fault activity (Yielding et al. 1992).

The paralic delta environment has produced a highly layered reservoir with many fluvial channels and permeability barriers giving a high degree of compartmentalisation.

Original repeat formation tester (RFT) data supports a stratigraphically well- connected reservoir model. Compartmentalisation is present due to stratigraphic layering involving laterally persistent mudstones resulting in low vertical permeability, and variable dimensions of channels and valley fills. Fluvial channel sandstones dominate flow, giving high permeability contrasts and vertical and lateral stratigraphic heterogeneity. Stratigraphy is hypothesised to be a strong control on the dynamic behaviour of the field (Flint 1998).

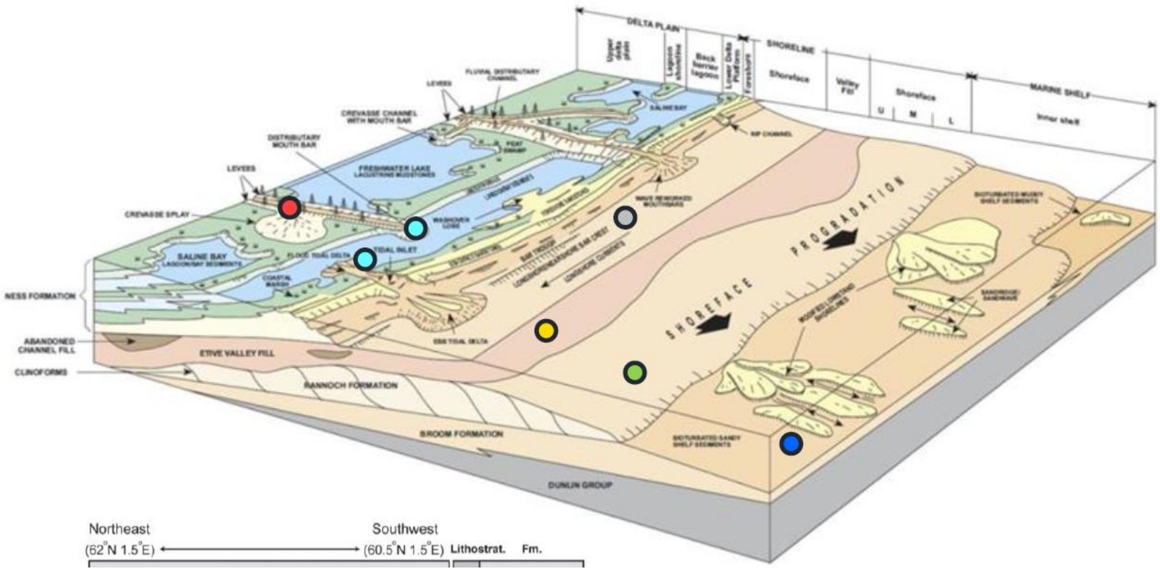


Figure 9- Depositional Environment of the Brent Group, modified from Millennium Atlas

1.7 Regional Evolution of the Brent

Two differing main published models explain the regional evolution of the Brent Group (Richards, 1992).

- The system as a northwards prograding delta, a southerly source and concentric facies belts through the basin. This is the more conventional model and has been documented extensively by authors including Budding & Inglin (1981), Ziegler (1982), Johnson & Stewart (1985) and Helland-Hansen et al. (1989). The model envisages growth of a thermally domed area to the south in late Early Jurassic or Early Mid Jurassic, where erosional products were shed off and prograded north along the Viking Graben. This resulted in the deposition of the wave dominated regressive deltaic succession with concentrically arranged facies belts across the graben (Richards 1992).
- A dominantly transverse sediment supply to the basin, with ensuing localised northwards progradation within the basin (Richards 1992). This accounts for the apparent derivation of material from adjacent platforms and describes rapid sea level fall and/or basin margin uplift in the late Toarcian or early Aalenian, resulting in a transverse supply of clastics into the graben.

1.7.1 Biostratigraphy

There is scope for more research on Brent Group biostratigraphy in order to develop understanding of the depositional system's evolution, as it is not extensively documented in literature. Controversy exists over the exact age of the Brent Group, with suggestions ranging from late Toarcian to early Bathonian (Ryseth 1989) or entirely post-Aalenian (Helland-Hansen et al. 1989). The majority of the Group has been suggested at Aalenian to earliest Bajocian age, with the upper part of the Group possibly extending into the Bathonian (Richards et al. 1990).

1.8 Petroleum System

The source of the oil is the Upper Jurassic Kimmeridge Clay Formation, over 1200 ft thick in the NW Hutton region and with a total organic carbon (TOC) of 4.5-6.5% (Johnes and Gauer 1991). The oil source became mature in the early Tertiary from 62- 50 Ma (Swarbrick, 1994), and the NW Hutton field was filled with oil between 49- 33 Ma (Swarbrick op cit), charged from the west (Gluyas et al, 2020)

The trap is a complex series of SW dipping fault blocks (Figure 7), sealed by the mudstones of the Upper Jurassic Heather and Kimmeridge Clay Formations (Gluyas et al, 2020).

The reservoir sandstones of the Brent Group were deposited in paralic settings (Flint et al 1998) and are associated with mudstones and coals. The reservoir sequence is thinned at the crests in NW Hutton due to Upper Jurassic rifting that resulted in the rotation and uplift of fault blocks. The Tarbert Formation is only seen off crest, parts of the Ness Formation are also missing, erosion prior to the deposition of the Etive Formation has removed significant parts of the Rannoch Formation across parts of the field (Gluyas et al, 2020).

1.9 Reservoir Quality

Reservoir quality is an important control on production performance.

Porosity and permeability of good quality sandstones are shown to decrease with increased burial depth (Gluyas, 1985). The prime Ness and Etive sandstones at the crest of NW Hutton (11,000 ft TVDSS) have porosities of 15-25% and permeability of 10mD to around 3D. The decline in permeability and porosity is relatively uniform in Greater Galapagos and has a porosity loss of around 5% per 1000 ft and just over an order of magnitude permeability loss over the same depth interval (Gluyas 1985).

Petrophysical and production data show rapid decline in reservoir quality in western fault block at depths below 1200 ft, where the production limit been defined at 12500 ft subsea based on well 211/27-A28. A similar decline with depth is seen in Eastern and Central blocks.

1.9.1 Diagenesis

Brent Group sandstones vary from very fine to coarse and are of a quartz-arenitic composition, with varying proportions of feldspar, mica and lithic fragments. The main pore filling minerals were found to be quartz overgrowths, calcite, siderite, kaolinite and illite (Scotchman 1989).

The same diagenetic processes occurred in the Hutton area Brent sandstones as elsewhere in the Brent Province (Gluyas 1985). Shortly after deposition concretionary calcite locally decreased porosity. After compaction feldspar dissolution occurred, along with quartz and clay cementation (typically kaolinite and illite with illite replacing kaolinite in deeply buried areas) (Gluyas 1985).

1.9.2 Types of Pore Space

3 main types of pore space were identified in Brent sandstones; intergranular pores, secondary pores and intercrystalline clay micropores (Scotchman 1989). Intergranular pores are the most significant in fluid storage and transmissibility. Coarse grained distributary channel sandstones with a low clay content have the highest intergranular pore space content (averaging 12.9 vol%), giving large interconnected pores and high permeability, resulting in these sandstones having the best reservoir quality. Also containing abundant intergranular pores (averaging 10.4 vol%) are the marine-bar facies sandstones. Secondary pores from the partial or full leaching of unstable grains like feldspar are present in all sandstones not cemented by early calcite, averaging 3.7 vol%). These pores tend to be poorly interconnected so only effectively enhance transmissibility and permeability when connected with intergranular pores. Large scale leaching of feldspars present in the Broom Formation has provided secondary porosity that has significantly promoted reservoir quality. Porosity in fine grained sandstones such as the Rannoch Formation has non-effective intercrystalline clay micropores in terms of fluid transmission. This is due to the very small pore throats and high tortuosity and capillarity. High authigenic clay content adds to this effect. This means porosity is relatively high, but with low permeability. In the Rannoch Formation the pore type is primarily associated with illite, and kaolinite in the Broom Formation.

1.9.3 Depth Control on Reservoir Quality

Controversy exists regarding controls on reservoir quality. Scotchman (1989) regarded burial depth and diagenesis as the main control by identifying significant increases in quartz cementation and illite authigenesis with depth.

Regionally, studies have shown temperature (and therefore depth) is the main control on illite formation. Several Brent studies show illite becomes abundant in reservoirs between 11,000-11,500 ft TVDSS.

The increased levels of quartz cement at depth are a main cause of porosity decrease. The less abundant clays have a small effect on porosity but a disproportionate effect on permeability due to their morphology, with illite having more of an effect than kaolinite. Scotchman (1989) provided evidence in fluid inclusions that oil migration and quartz cementation occurred simultaneously in sandstones. Migrating oil may displace water from crest to flank which may inhibit cementation, resulting in crests having a very high reservoir quality (Oxtoby et al 1995).

Special circumstances in deeply buried prospects with Brent Group sandstone reservoirs (deeper than 11500 ft TVDSS) are required for the reservoir to be of prospective quality, these include:

- Early oil emplacement- shown to retard illite formation
- Chlorite overgrowths retarding quartz cement
- Micro quartz cements retard mechanical compaction
- Acidic pore water dissolution of potassium feldspar

1.9.4 Facies Control on Reservoir Quality

Conversely, Bridge Petroleum Ltd theorised the main control in the Darwin area is depositional Facies Association, with grain size exercising the most control. Burial depth was regarded to exercise a secondary control on poroperm pattern.

Depositional factors are a significant control on reservoir quality in the NW Hutton field. The most important factor is grain size where coarser sandstones have higher porosities and permeabilities, hence the best reservoir qualities. Distributary channel sandstones have the largest grains and therefore best reservoir quality. The delta-front sandstones in the Rannoch Formation the smallest grain size and poorest reservoir quality. An exception is the coarse-grained Broom Formation sandstones, which have abundant carbonate cements. Another important control on reservoir quality is detrital clay content, which is greatest in the fine-grained sandstones where it significantly reduces permeability and porosity, such as in the Rannoch Formation. The combination of grain size and total clay mineral content, for example in coarsening upwards marine bar sequences, leads to both horizontal and vertical large-scale variation in reservoir quality within the sandstone bodies and the formation of lateral and vertical permeability barriers.

1.10 Developmental History

NW Hutton was discovered in 1975 by well 211/27-3 (Johnes and Gauer 1991), with a virgin pressure of 17.1 MPa (Swarbrick 1994). 7 wells were used to appraise NW Hutton, none of which are in fip3.

NW Hutton was reported to contain 1157 mmBBL oil in place in 1983 and reserves were estimated at 273 mmBBL (Gluyas et al, 2020). These figures have been significantly reduced throughout the field's production life, down to 576 mmBBL oil in place by Amaco in the cessation of production document in 1997. This figure has been criticised by Gluyas et al (2020) as relying on some non- geological assumptions, such as only including oil accessible from the platform and rock above a poroperm cut off, despite proven historical flow in similar sandstones beneath these cut-offs. STOIIP was estimated by Fairfield as an excess of a billion barrels of oil. There is no data on oil in place and reserves, or net to gross for just fip3.

North West Hutton was first operated by Amaco in 1972. The company developed it using a conventional platform. In 1998 BP became the operators, ceasing production in 2002 with 135 mmBBL produced and platforms were removed. In 2009 Fairfield Energy acquired the abandoned field, followed by TAQA in 2012. Finally, the current operators Bridge Petroleum in 2016, along with the rest of Greater Galapagos.

Operators (bold) and licence holders of NW Hutton	**Dates of operators**
Amoco	1972
Gas Council	
Mobil	
Amerada Hess	
North Sea Inc Petrobras	
Ceico	
Enterprise	
Texas Eastern	
BP	1998
Shell	
ExxonMobil	
Fairfield	2009
TAQA	2012
Bridge Petroleum	2016

Table 2- Operators (with dates) and licence holders of NW Hutton (Gluyas et al, 2020)

Initial drilling in NW Hutton successfully emplaced a suitable drainage network for the field. Production began in April 1983, however rapidly falling production meant that within 6 months it was supported by gaslifting. By the end of 1985 100% of production was gaslifted.

In fip3 production began with A03Z in July 1983 and ended in July 1999. Many wells had rapid decline rates (Scotchman and Johnes 1990), resulting in a water injection programme beginning in February 1984 with nine wells in a mid-field line drive. In 1992-92 expansion commenced into four areas of the field which had not benefitted from the original pattern. The water injection programme in fip3 commenced with A16 in December 1984, A21 in March 1985 and A08Z in August 1991.

Production rate in NW Hutton rapidly built up, with the instantaneous daily rate peaking at 86,500 bopd in May 1993, never reaching the planned plateau rate of 100,000 bopd (Gluyas et al, 2020). Production rate fell rapidly to 50,000 bopd (barrels of oil per day) in September 1983 and remained unstable as field pressure quickly declined and operators struggled to maintain production levels. Well profiles showed a high initial oil rate followed by rapid decline in oil rate and well pressure as gas oil ratio increased rapidly, typical of wells draining a limited rock volume (Gluyas et al, 2020).

The second drilling phase from 1991-92 was considered a catastrophic event in NW Hutton's history. Eleven wells were drilled (40-51), including A40, A41, A41Z and A48 in fip3. These were drilled between with existing wells with the aim of extracting unswept oil, however in general they were swept, giving very small incremental recovery which failed to recoup expenditure. This event was the end of the developmental drilling.

Compressor problems in 1991 meant NW Hutton was shut for 7 months. Performance was significantly worse than before after the field was brought back into production. This was attributed to crossflow effects in the wells from high pressure watered out zones to lower pressure zones with low water cut. This may mean that intermittent production may not be effective.

Field shut in occurred late 1986 as approximately 10,000 bopd production had been lost. By this time significant breakthrough meant the more permeable sandstones had been watered out, causing problems after shut in as injection water flowed from high pressure high quality sandstones into the unswept low quality sandstones. Sulphate in sea water reacted with dissolved barium in the connate water, resulting in barium sulphate precipitation near the wellbore in the remaining unswept sandstones, severely reducing permeability (Gluyas et al, 2020). Despite the solution of a scale inhibitor to the injection fluid, nothing was done to solve this (Gluyas et al, 2020). From the mid 90s to the end of field life production was around 5000 bopd.

The fixed NW Hutton platform was decommissioned by BP, with the removal of the jacket following topsides, leaving just 49m of footings extending from the sea- bed and the cuttings pile (Nixon 2013).

1.11 Reservoir Challenges

Reservoir management challenges experienced in North West Hutton include well integrity and scaling issues, a very poor injectivity profile (well spacing, thief zones and short circuiting), and low voidage replacement ratio (0.7). (Bridge Petroleum Ltd). Operational challenges were also faced including high tortuosity complex wells with tricky access, and water handling constraints that limit injections.

Initially high production rates which rapidly fell have been is attributed to by highly permeable channel sandstone bodies in the Ness Formation (Gluyas et al, 2020). These are at right angles to the main fault direction, resulting in very fast depletion. Water injection support mostly flowed through the high permeability sheet sandstones, and although they helped sustain production, they were not very effective at sweeping sandstones above and below them. Complex faulting and compartmentalisation are also considered to be factors in the previous poor field performance. (Gluyas et al, 2020).

Well spacing on NW Hutton has been criticised as too dense and restricting expected ultimate recovery per producer, and final wells have been reported to be even more poorly positioned, evident in production statistics. Many wells had low productivity due to either being drilled into existing flood fronts/ water injection shadows or stealing production from existing wells (Gluyas et al, 2020).

Most of the best producing wells in NW Hutton were drilled into the shallow crest, however a few deeper wells, such as A14 in fip3 were highly productive. A14 was drilled far from its nearest injector A08Z, although pressure assistance and an effective flood front was reported. Many productive deep wells had poor sweep design attributed to poorer performance as producers were converted to injectors rather than new wells being created (Gluyas et al, 2020).

1.12 Future potential

North West Hutton is currently owned by Bridge Petroleum. Although the field has a poor reputation in the industry, data analysis and careful consideration of facts has allowed the company to identify the field as a ‘dormant Brent giant awaiting redevelopment’. Oil price has dramatically dropped twice since 2008, meaning any commercial challenges to redevelopment will not just depend on reservoir properties.

New technology is currently under consideration to improve recoveries and reduce costs. Subsurface evaluation has identified significant quantities of unproduced oil remaining in North West Hutton, which along with technical reservoir understanding would require redevelopment of production facilities including new wells and the topside of the NW Hutton platform (Gluyas et al, 2020). Existing reserves may be accessed using newer tried and tested technology which was not available or not applied in the original development. The option of horizontal drilling should be addressed, as many mature fields have been revitalised with this tactic.

2 Methodology

This chapter aims to introduce all of the datasets available for the research and to summarise the methods used for data collection and analysis.

2.1 Objectives and Overview

The primary geological considerations are to identify high quality reservoir bodies in fip3 and their geometry, and to determine the nature and importance of heterogeneities. The heterogeneities may take the form of shales or other impermeable layers, varying continuity and interconnections of the good quality reservoir layers, directional permeability trends caused by depositional environment or diagenesis, or fracture and fault trends acting either as flow barriers or open conduits.

The following tools and techniques have been used, based on the below database, in order to achieve the objectives of this study:

- Review sedimentological studies undertaken on North West Hutton field wells, primarily Ichron (2010), Dundas (2014), Flint et al (1998)
- Interpretation of facies associations from 3 cored wells and extrapolate to non-cored wells
- Gain and understanding of sandbody geometries and architecture
- Sequence stratigraphy allowed for inferring and predicting internal connectivity, stratigraphic compartmentalisation and the location of good quality reservoir rocks
- Permeability and porosity study of formations and facies

The second part of the study will integrate sedimentological results with production data, water injection data, RFT and production logging tool (PLT) data in order to identify reasons for previous performance of fip3 and identify remaining potential or underdeveloped areas.

- Analysis of production and injection data
- Identifying areas of aquifer and artificial pressure support
- Interpreting water injection paths and swept areas/ reservoir layers
- Identifying compartmentalisation and areas of fip3 in pressure communication

2.2 Database

The database of comprehensive static and dynamic data:

- 14 exploration wells, 2 failed, 3 converted to water injectors
- 14 wireline logs (data provided by Bridge Petroleum Ltd).
- Core description and facies interpretation of 1 well (Ichron (2010), Dundas (2014)

- Core description of 3 wells (BGS, Drill Core)
- 14 CPI logs (data provided by Bridge Petroleum Ltd).
- Geotechnical reports from well data
- Well top data for 14 wells (data provided by Bridge Petroleum Ltd)
- Static Petrel models (data provided by Bridge Petroleum Ltd)
- Fault map (exported to Petrel)
- Production data from 16 years of production (data provided by Bridge Petroleum Ltd)
- RFT data for 12 wells (data provided by Bridge Petroleum Ltd)
- PLT data for 14 wells (data provided by Bridge Petroleum Ltd)
- Oil water contact (OWC) and oil down to/ water up to (ODT/ WUT) data (data provided by Bridge Petroleum Ltd)
- Permeability and porosity data (data provided by Bridge Petroleum Ltd)
- Multiple Brent fields publications, including detailed sequence stratigraphy of the NW Hutton field (Flint et al 1998)

2.3 Geology

2.3.1 Core Descriptions

Core descriptions were made of wells A14, A15 and A37. Observations were made on lithology, colour, sedimentary structure, texture, degree of bioturbation, cyclicity, thickness, dolomitization and fossil content. These were based off high resolution colour photographs from the BGS**.** Core descriptions contracted by Amoco of A15 (by A. Moffat 1984), A14 (by A. Moffat 1986) and A37 (by D. Brewer 1988) were available, these data were used in conjunction with my own observations for information, such as grain size, that could not be gauged quantitatively from the BGS photo alone.

Detailed description of the Ness Formation in particular is required as it is highly variable and contains the most oil in the Brent Group reservoir (Livera 1989).

The lack of lateral perspective on a core-based study made it difficult to identify larger scale sedimentary structures.

2.3.2 Wireline and Composition Logs

Scans of wireline well logs are available (provided by Amoco). They include gamma ray, resistivity, interval transit time, perforation interval, lithology and a brief lithological description. The descriptions recorded are semi- quantitative estimates and describe perforation interval, lithology, modal grain size, roundness, sorting, colour, hardness, bioturbation, fossil type, cementation and occasionally visible porosity and permeability. This has been of particular use in interpreting sedimentary facies where core is not available.

They have been used alongside computer processed image (CPI) logs to delineate and correlate different sedimentary facies by identifying formation tops. Wireline log data is used in conjunction with well top data provided by Bridge Petroleum to mark formation/ layer tops and get a lithological description and facies interpretation of each. Rock quality can be described for each well, which can show how rock quality varies throughout fip3, and if this has a relationship to production performance. and how this varies in different parts of the field.

2.3.3 CPI Logs

The CPI logs included Gamma Ray, volume of shale (Vshal), Neutron Density, Resistivity, Water saturation, Lithology, Permeability and Porosity. These were all calibrated to MD and TVDSS. The Gamma Ray log measures naturally occurring gamma radiation in the well and is a good lithology indicator and correlation tool. Vshal can be calculated from this. The Neutron Density log measures electron density, related to bulk density and can distinguish between rock lithologies, recognise the presence of heavy minerals and identify fractures as well as differentiating between oil and gas in the pore space. It is often used to calculate porosity. Resistivity measures the electrical resistivity of the formation and can differentiate between conductive (usually water or mud filtrate) and non-conductive fluids (usually oil or gas). Water saturation is an indicator of if oil or water fills the pore space.

Interpretations on lithology and depositional environment based on the proxies can therefore tentatively be made on lithology, volume of shale, grain size, fluid saturations, porosity and permeability.

2.3.4 Reservoir Subdivision

Original reservoir subdivision of Bowen (1975), and Deegan & Scull (1977) are not sufficient to model the production behaviour of the field. This is due to the sub reservoirs were found within the units (Johnson & Stewart 1985), consisting of extensive shales and abandonment coals, particularly in the Ness Formation. These form horizontal barriers to vertical oil flow, meaning sandstone bodies between them behave in their own pressure regimes. For this reason, RFT data have been analysed within the study. The layer cake framework of coals and shales has meant that the reservoir has been subdivided (Bridge Petroleum) into UNA-G and LNA-G, and the sandstone bodies pressure between them contrasted to see which have been depleted of oil and which are at original pressure.

Identifying the exact depths of formations and subdivisions location was based on well top data (Bridge Petroleum) and altered where necessary. Isopach maps of the Broom, Rannoch, Etive, LNA, LNB, LNC, LND, LNE, LNF, LNG, Mid Ness Shale, UNA, UNB, UNC, UND, UNE, UNF, UNG and top Upper Ness were then created using this data and exported into Schlumberger geomodelling software Petrel.

2.3.5 Stratigraphic Correlation

Identification and re-examination of key surfaces and regressive transgressive cycles in the area was used to establish a stratigraphic framework for correlation. The cornerstones for this study were well top data (Bridge Petroleum) and detailed sequence stratigraphy undertaken by Flint et al. (1998).

The layers correlated were the Broom Formation, Rannoch Formation, Etive Formation, LNA, LNB, LNC, LND, LNE, LNF, LNG, Mid Ness Shale, UNA, UNB, UNC, UND, UNE, UNF, UNG and top Upper Ness.

This data was used to create 6 multi- orientated sections across fip3 within Petrel, these are:

- A15- A41Z-A29
- A03Z-A16-A32-A08Z-A40-A14
- A32-A37
- A16-A21
- A03Z-A21-A37
- A29-A21-A37-A14

Cross- sections were corrected to TVDSS. They are a useful predictive tool for fip3 architecture and reservoir quality in understanding reservoir performance. However correlative sandbodies may be of different depositional facies and may not form part of the same depositional systems tract and might not be in good communication. Therefore, a study on depositional facies and schematic diagrams recreating the architecture of sandbody geometries have also been used in this study (described in section 2.3.7).

2.3.6 Interpretation of Facies Associations

It is important to understand the depositional environment and reservoir facies architecture to predict continuity between wells for a better understanding of the architecture between wells.

This study has used Dundas, 2014 grouping and simplification of facies associations for reservoir modelling purposes. Depositional environment has been interpreted at a facies association level (grouping of similar or identical associations), based on Dundas (2014) grouping for reservoir modelling purposes.

2.3.6.1 Facies Associations of Un-Cored Sections

Core facies associations were matched with wireline log responses and lithological descriptions on composite logs to identify facies and depositional environment in un-cored wells. Shape and log character, as well as Vclay distribution were used in identifying facies associations. Facies identification for this study could not be based on permeability and porosity data due to having no data in un-cored wells. Fieldwide markers were also useful in correlation. Where necessary

Dundas's (2014) decision tree has been used to differentiate major reservoir units in un-cored sections (Figure 10). The criteria for which each has been differentiated is described below:

Fluvial Channel Bodies

Fluvial channels show a very wide range of petrophysical properties (Dundas 2014). Channels overall have upwards fining tendencies, shown as bell shapes in GR and wireline logs. Bases of channels usually are sharp, however mud clast basal lag at the base may result in a higher GR/ Vclay response at the base of the body, resulting in a gradational base. Channel sandbodies porosity tends to decrease upwards (Dundas 2014), with burial depth being a major control on absolute porosity.

Dundas' (2014) revaluation of the Ichron (2010) interpretation points out the lack of clarity in evidence for differentiation between channelized and non-channelized higher energy nearshore depositional settings. They appear similar on logs, therefore more detailed sedimentological research and documentation is required to accurately differentiate them.

Multi-storey fluvial channel bodies: Thick bodies (around 3 times thicker than single storey- Dundas (2014)), lower part is very clean sandstone (<5% Vclay), cylindrical GR/ Vclay log shape, capped by serrated bell shape of channel upper bar or abandonment deposits.

Single-storey fluvial channel bodies: Thin bodies, usually very clean sandstone in lower part, with bell shaped GR/ Vclay response

Bay margins, Bay margin heterolithic, Bay floor mud

Sheet sandstones in back barrier lagoon/ bay fill setting:

The sandstones in this setting (bayhead delta, washover/ minor mouth bar sandstones) are non-channelized and may be interpreted to form ellipsoidal sheets (Dundas, 2014). They have a funnel shape on GR and Vclay logs due to upwards coarsening in grain size. Axial bayhead delta have very clean sandstone, whereas distal bay head deltas or mouth bar/ washover sandstone lack very clean sandstone, so it may be possible to distinguish them this way. Bayhead deltas tend to have a gradational base, inviting confusing with fluvial channels, but they are much thinner than channels.

Heteroliths may be present in an overall upwards coarsening motif. Variations on the log make these difficult to identify; anomalously sharp bases due to coal beds or dirtying upwards due to bioturbation during abandonment (Dundas 2014). Sheet sandstones tend to show an upward increase in log porosity (Dundas 2014). Thin and heterolithic channel bodies commonly lack distinctive log signatures and may be confused with distal bayhead delta, washover, minor mouth bar and bay margin heterolithic.

Thicker beds are easier to identify based of log response, however thinner beds in these associations often lack character and may be easily confused with heterolithic single storey channel bodies or thin crevasse splay sandbodies.

Distributary channels and coastal zone sandbodies

Distributary channels have an upwards dirtying bell-shaped GR/ Vclay profiles, which lack or only have minor intervals of very clean sandstone (Vclay <5%) Dundas (2014). These bodies are much thicker than fluvial sandbody stories.

Both proximal and distal shoreface deposits have large scale bell and funnel shaped GR/ Vclay profiles. Slightly dirty sandstones are middle shoreface and very dirty indicates lower shoreface and offshore transition zone. The nature of the density/ neutron log may be variable between wells due to the major control of depth on porosity (Dundas 2014).

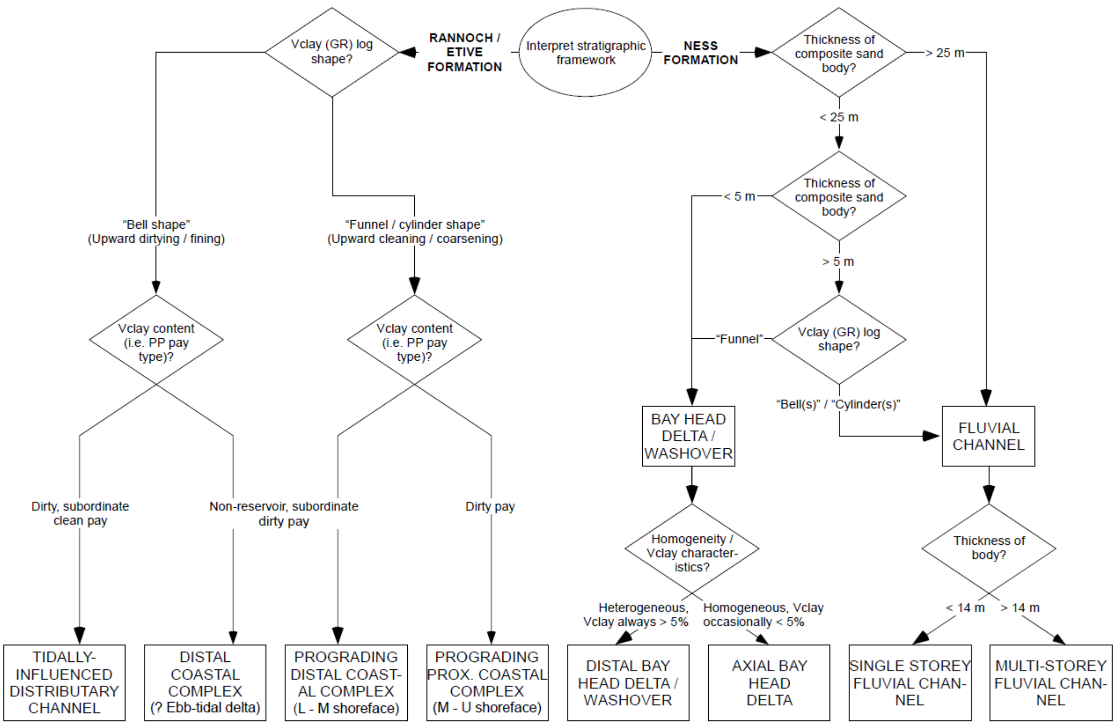


Figure 10- Decision tree for interpretation of depositional facies from wireline logs, Darwin Field (Rannoch, Etive and Ness Formations) (Dundas, 2014)

2.3.7 Mapping Sandbodies

The aim is to predict the 3D sandbody geometries, types and inter-connectivity of sandbodies in order to gain and understanding of the architecture of these reservoir sandstone channels and sheets between wells in fip3. Schematic diagrams of the sandbodies in the Etive and Ness Formations were produced.

Due to the lack of exposure of the Brent Group, width and cross-sectional area are very difficult to determine. The thickness of the channels or sheets were measured using TVDSS of CPI logs after facies interpretation. Width of channels or extent of sandbodies were unknown and were compared to widths and thicknesses of sandbodies for the corresponding facies association in Gibling (2006). The paper reviews the terminology for describing channel body geometry and has a wide dataset of over 1500 bedrock and quaternary fluvial bodies where width (W) and thickness (T) have been recorded. 12 types of channel body have been recorded and presented with geomorphic setting, geometry, internal structure and W and T ratios are presented.

It should be noted that the result is only one of a number of potential geometries of sandstones in the Ness Formation and may not be correct. Differing or multiple sizes of fluvial channels mean it is difficult to estimate widths of channels just based on thickness estimated from CPI logs. There is a huge degree of uncertainty with mapping, relations to channel size and the controls sequence stratigraphy has on this may be resolved with a much more detailed study of petrography and textural attributes of channel bodies.

2.3.8 Porosity and Permeability

Porosity and permeability data are only available for cored wells.

Cumulative permeability by depth was plotted for wells A08Z, A14, A15 and A37. This gives a visual indication of which the high and low permeability layers are.

Poroperm data has been plotted for 12 NW Hutton wells, by formation. This includes porosity vs log horizontal permeability, log vertical vs horizontal permeability, by formation, log horizontal permeability vs depth, by formation and first porosity vs depth, by formation.

Data came from wells in fip3 (211/27-15, 211/27-34), NW Hutton (211/27/9, 211/27-10. 211/27-11. 27-1A, 211/27-4A. 211/27-A1, 211/27-37, 211/27-c-12, 211/27/A34, 211/27-9z, 211/27-A15, 211/27-2, 211/27-4a) and Hutton (211/28-1z, 211/28-H1). Data from nearby fip3 was included as there is a lack of data in fip3.

Permeability and porosity data have been plotted for A15 by facies association in order to identify which are the best reservoirs, and to identify if facies is a major control on reservoir quality in fip3. Data was gained from using permeability and porosity values on the CPI log.

2.4 Dynamic data

2.4.1 Production Data

Gas oil ratio (GOR), water oil ratio (WOR), injected water, well head pressure (WHP), cumulative oil, cumulative water and oil rate have been plotted against time on a well by well basis. Gas has not been plotted as NWH gas production is minimal (Johnes and Gauer 1991).

Oil production rates over time of wells in close proximity have been analysed to see if newer wells are "stealing" production from older wells.

Water breakthrough times from which injector have been mapped for each well in order to see the extent of pressure support in fip3, which layers have been swept, and which layers the water-front travels through. This has been achieved by plotting log WOR and log WOR against time, based on Chan's (1995) paper, and compared with water injection profiles from nearby injectors. Water breakthrough interpretations have been based on rapid WOR increases, often coupled with a decrease in GOR and increase in oil rate. WOR is very variable in many wells so the relative timings of water breakthroughs have been used to gauge the most likely breakthrough event.

Linear WOR plots were also used to evaluate recovery efficiency, where 20 WOR indicates 95% water cut meaning that the well has likely reached potential (unless non permeable layers have not been swept and retain oil). The latter may be tested by comparing PLT to permeability data.

Production data are in the appendix.

2.4.2 Bubble Plots

Bubble maps (Figures 38-41) were created using cumulative oil, water injected and produced per well, where the bubble area is representative of the volume of water/ oil injected or produced. This is to visually represent well performance and see spatial and geographical trends related to proximity to faults, injectors, high quality reservoir etc.

2.4.3 Net Sandstone Calculation

A net sandstone calculation was undertaken in all of the study wells in fip3, then displayed in map form (Figure 12). This was achieved by using a cut off value for gamma ray curves on the CPI logs. Due to apparent variations in GR tool calibration a subjective approach was taken in which a range of 2.4-2.6 (G/C3), and resultant intervals of net sandstone were then measured. Cemented sandstones were taken away from the net sandstone calculation.

2.4.4 Repeat Formation Tester

RFT pressure data analysis was used to provide as an independent test of sandbody continuity between wells and reservoir sub-divisions. It is used to look at reservoir intercommunication, reservoir pressure and make inferences about compartmentalisation of the field.

RFT data, from the time of drilling of each well, was available for 12 wells for most reservoir sub-divisions, against TVDSS. Original pressure gradients from oil and water were used to establish the depletion behaviour of individual sandstones relative to well chronology.

2.4.5 Production Logging Tool

The production logging tool (PLT) was used to observe which layers produce most, and which and take most water injection. This can help identify good reservoir sandstones. For 4 wells this has been compared to cumulative permeability to indicate if it is only the highly permeable layers that take injection. PLT data also can help identify production problems such as leaks or cross flow and shows which layers have been perforated and reperforated.

It is unclear if some layers produce poorly as a result of lack of injection and pressure support or less initial oil in place, so PLT has been used in conjunction with other data. It also does not identify if it is oil or water being produced but water saturation data on CPI logs distinguishes between water and oil.

2.4.6 Oil Water Contacts

OWC or oil down to/ water up to (ODT/ WUT) data was provided for 5 wells (A08Z, A14, A16, A32 and A37) by Bridge Petroleum. OWCs for the other wells were inferred using CPI logs using water saturation data. Where there is a shale layer the contact can be unclear, so ODT or WUT was used. In some cases, the contact could not be found and was inferred to occur below the Broom Formation. The aim was to understand where formation water is producing, the location of perched water and if this is affecting pressure support of wells, and where the OWC is. Bridge Petroleum interpreted the OWC to be just above A14 and A40, this will be tested by using the depth structure Petrel map to indicate if there is a structural low in this area, hence likely water pooling.

2.4.7 Faulting

The faults considered in this study are based on the Simon Kelk's fault study for Fairfield and provided Petrel fault map (data provided by Bridge Petroleum Ltd). A depth structure map has been created in Petrel based on the existing fault map. This can be used to highlight structural lows, where water has the potential to pool. The fault map was not used in creation of Isopach maps as deposition predated faulting (Richards 1992).

2.5 Limitations

It was acknowledged that the dataset is limited and old, will contain errors, however small. Localised and more detailed sedimentary modelling is required, particularly of the Ness Formation to predict reservoir geometries. Detailed description of the Ness Formation is required as it is extremely variable, particularly in NW Hutton, and it contains most of the oil in the Brent Group reservoir (Livera 1989). There is huge room error for facies identification in un-cored wells.

This study works on a very short time frame and lacks resources to do a more in-depth study.

3 Results

The following chapter presents the results from the study.

3.1 Geology

This section focuses on aspects of sedimentology for the Brent Group intervals of fip3, NW Hutton Field, UKCS. A comprehensive understanding of the factors controlling the permeability, geometry and connectivity of the reservoir quality sandstones and their associated heterogeneities is vital for understanding the hydrocarbon reservoirs contained within them. Studying the controls on the distribution of sandstones in a deltaic sequence is vital for predicting and extrapolating sandstone rich lithologies beyond data coverage.

3.1.1 Facies Associations

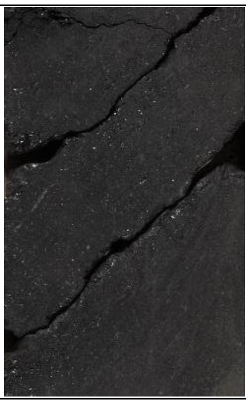
Typical core characteristics (based on A14, A15 and A37) from each facies association are summarised below in Table 3.

Facies Association	**Tidal Shoal**	**Offshore Transition Zone**	**Lower Shoreface**
Typical Core Expression			
Constituent Facies	• Coarse argillaceous sandstone • Micaceous siltstone	• Fine micaceous siltstone • Interbedded bioturbated heteroliths	• Fine, massive and laminated sandstone • Calcareous fine sandstone
Lithological Description	*Coarse clean sandstone* at base: Mid brown, oil stained, firm, friable, medium to coarse, can be granular, poorly sorted, sub angular, white and clear quartz, loose silica cement with slight calcareous possibly dolomitic content, rare quartz overgrowths, locally fine grain, tight, laminated with mica rich carbonaceous laminations and shaley partings, occasional irregular fine mid grey argillaceous bands, rare minor tight streaks of siliceous and pore plugging kaolinite cement and minor black carbonaceous laminae and silvery white muscovite.	Silt interbedded with sandstone at base, coarsens up to sandstone. Abundant carbonaceous debris to the base *Micaceous siltstone:* very finely interlaminated with white, silica cemented silt and fine sand. *Sandstone:* Mid to light brown with a light oil stain, hard, fine grained, very uniform, angular, well sorted clear quartz in a non-calcareous strong silicic cement, abundant mica in matrix, poor porosity and permeability. *Micaceous laminae:* sparse, pure mica and with a shaley grey appearance, often hard	*Sandstone*: Light brown, very light oil stain, fine grained, well sorted angular quartz in hard silicic cement, abundant micaceous partings and laminae, poor porosity and permeability. *Calcareous sandstone*: light grey, very hard, fine grained, well sorted angular, clear quartz in minor silicic cement and very calcareous microcrystalline cement, no visible porosity

	Excellent visible porosity and permeability, strong oil odour. *Coarse argillaceous sandstone*: Patchy grey and off white, coarse grained or granular, poorly sorted sub angular, white and clear quartz, loose silica cement, strongly contaminated with grey argillaceous material. Mica in matrix and clasts, poor to moderate visible porosity.	and silica cemented, laminae often convoluted.	
Sedimentary Characteristics	Grey argillaceous bands Mud draped CB	Micaceous, convoluted laminae HCS (Flint) Possible fossil rain pits	Micaceous laminae HCS (Flint)
Accessory Minerals/ Additions	Occasional quartz overgrowths Siliceous and kaolonitic cement Muscovite	Muscovite Biotite	
CPI Log	Clean, even in argillaceous bit, good porosity and permeability, coarsening up, locally cemented, high N:G	Coarsening up, very little porosity or permeability Composed of several coarsening up minor parasequences, cementation	Coarser sandstone than O.T.Z, still fine, poor reservoir quality, little porosity or permeability Thin cementation indicated
Sandstone Geometry	Sheet	Sheet	Sheet
Depositional Environment	Tidal shoal/ sandbar	Wave and storm regressive dominated shoreface succession	Wave and storm regressive dominated shoreface succession
Mean Porosity	0.187	0.093	0.138
Mean Permeability	202	0.673	0.574
Typical Formation	Broom, Upper Ness	Rannoch	Rannoch
Reservoir/ Non Reservoir	Reservoir	Poor reservoir	Poor reservoir

Facies Association	**Middle Shoreface**	**Distributary Channel**	**Bay Margin Heterolithic**
Typical Core Expression			
Constituent Facies	• Fine, massive sandstone • Coal	• Coal • Medium sandstone • Thin micaceous shale	• Dark grey shale • Heteroliths • Sandstone
Lithological Description	*Sandstone:* Light brown, very light oil stain, fine grained, well sorted angular quartz in hard silicic cement,	*Sandstone:* Mid brown, uniformly oil stained, firm, moderate silica cement possibly increasing with	*Heteroliths:* Laminated siltstone and mudstone, hard, brittle, fissile, light grey, tight kaolonitic in rich

	abundant micaceous partings and laminae, poor porosity and permeability. Degree of cementation increasing with depth. *Coal:* Thin coal beds, interpreted by CPI as shale	depth. Locally friable, medium grained, well sorted clear non micaceous vitreous quartz, grain supported non calcareous or carbonaceous. Towards top scattered mica flakes in groundmass. Below this mica is confined to very micaceous laminae and partings 1-2mm thick, sparsely distributed. Uniform oil stain Good porosity and permeability. Occasional thin micaceous shale in fine laminae. *Coal:* Thin ½ inch beds, slightly pyritic.	quarzitic cement, siltstones are light brown, very silty mudstones with black vitreous inclusions, common carbonaceous shaley partings rich in mica, biotite rich micaceous partings *Sandstone:* Medium brown, friable, weakly cemented, medium- coarse, commonly gritty, clean, vitreous, sub angular to sub rounded, occasionally rounded, very coarse, moderate sorting, clean, homogenous, well sorted, rarely carbonaceous, grain supported, concavo-convex to tangential grain contacts, very good porosity and perm. Very friable and rubbly at base.
Sedimentary Characteristics	HCS	Trough CB, Planar- tabular CB with mud drapes Micaceous partings and laminae	Micro laminations of siltstone
Accessory Minerals/ Additions		Pyrite Abundant coaly clasts Mica flakes	Occasional pyritic nodules Micromica Abundant silica cement Abundant plant fragments in shale
CPI Log	Coarsening up parasequences, coarser than lower shoreface, common cementation	Fining up, good porosity and permeability, generally thick Often sharp erosive base	Poor permeability and porosity Generally thin
Sandstone Geometry	Sheet	Channel	
Depositional Environment	Wave and storm regressive dominated shoreface succession	Incised valley complex, distributary channel fill	Ichron: Bay environment (Ichron) Back barrier lagoon with micro-tidal system (Dundas)
Mean Porosity	0.144	0.201	0.117
Mean Permeability	96.69	140.6	2.291
Typical Formation	Rannoch, Lower Etive	Etive, Lower Ness	Ness
Reservoir/ Non Reservoir	Poor reservoir	Reservoir	Non reservoir

Facies Association	**Fluvial Floodplain Mud Rocks**	**Bayhead Delta- Distal- Marginal**	**Fluvial Multi-Storey Channel Type A**
Typical Core Expression			

Constituent Facies	• Carbonaceous shale • Coal	• Shale • Fine sandstone	• Medium sandstone • Shale
Lithological Description	*Carbonaceous shale:* very dark grey, matt black, firm, brittle, sometimes woody, vitreous and sub conchoidal, interval very fragmented in core. *Coal:* Black, resinous, vitreous laminations, flasers, hard, brittle, blocky, splintery, sub conchoidal fracture, locally pyritic nodules	*Shale:* Dark grey, hard, brittle, probably silica cemented, non calcareous, micromicaceous and slightly carbonaceous *Sandstone*: Light brown, oil saturated, hard, fine grained, clean, vitreous quartz, sub angular, moderate to good sphericity, unimodal, clean, homogenous, locally kaolinitic with coal and carbonaceous laminae, well cemented, locally with quartz overgrowths towards base, poor visible porosity	*Sandstone*: Medium brown, oil saturated, well cemented, medium grained, clear vitreous quartz, sub rounded, good sphericity, unimodal, well sorted, grain supported, moderate porosity) with silty micro laminations *Beds of carbonaceous siltstone:* light grey, hard, tough, coarse, quarzitic silt with very fine sand, tight, abundant micaceous and carbonaceous laminations, shaley partings *Shale*: Occasionally at top of sandstone, dark grey, hard, brittle, splintery, fissile, micromicaceous, non calcareous, abundant silty micro laminations
Sedimentary Characteristics			Silty micro laminations
Accessory Minerals/ Additions	Locally pyritic nodules in coal		
CPI Log	Thin, no porosity or permeability	Coarsening up	Good clean sandstone, fining up, high N:G
Sandstone Geometry		Sheet	Channel
Depositional Environment	Fluvial floodplain	Bay head delta lobate sheet sandstone cut by distributive channels that becomes increasingly muddier, finer and bioturbated in a distal direction	Distributive channels cutting delta
Mean Porosity	0.105	0.164	0.142
Mean Permeability	0.153	2.533	8.257
Typical Formation	Ness	Ness	Ness
Reservoir/ Non Reservoir	Non reservoir	Non reservoir	Reservoir

Facies Association	**Fluvial Multi-Storey Channel Type B**	**Bayhead Delta**	**Bay Margin**
Typical Core Expression			
Constituent Facies	• Medium sandstone • Carbonaceous siltstone • Occasional coal	• Sandstone • Shale	• Mudstone • Siltstone • Sandstone
Lithological Description	*Sandstone:* Medium brown, uniformly medium grained, minor coarse grain firm, moderately well sorted clear vitreous quartz, varying amounts of silica cement, but occasionally well cemented and hard with minor shale/ siltstone interbeds, slightly carbonaceous throughout. Uniform generally, commonly interlaminated with carbonaceous siltstone. Generally good visible porosity, abundant mica, carbonaceous laminae and flasers. *Carbonaceous siltstone:* Light grey/buff, hard, coarse texture with minor very fine sand, silica cemented, abundant coarse mica, particularly in association with carbonaceous material, Only weak occasional silica cement, contaminated by diesel in mud. *Coal:* Occasional thin beds, black, vitreous, woody texture, subconchoidal	Alternating sandstone and thin shale *Sandstone*: Light brown, oil saturated, hard, fine to upper medium grained, clean, vitreous quartz, sub angular, moderate to good sphericy, unimodal, clean, homogenous, locally kaolonitic with coal and carbonaceous laminae, well cemented, locally with quartz overgrowths towards base, poor visible porosity *Shale*: Dark grey, hard, brittle, silty, sub fissile, micaceous, non calcareous	*Mudstone:* Medium grey brown, hard, blocky, brittle, coarse quarzitic silt non calcareous *Siltstone:* Light grey, quarzitic, sandy in part, hard, brittle, blocky, tight Shale is dark grey, dull, earthy also waxy, polished, splintery fissile, non calcareous, minor carbonaceous laminations, thin interbed of kaolonitic sandstone *Sandstone:* Very fine grain size with upper coarse, medium brown, oil stained, silicified texture, polymodal, moderate sorting, clean, occasionally carbonaceous laminations, grain supported with siliceous cement, quartz overgrowths, poor to moderate porosity.
Sedimentary Characteristics	Clasts at base, roughly spherical, up to 8cm Carbonaceous laminae and flasers	Flasers Laminae	Occasional carbonaceous laminations
Accessory Minerals/ Additions			
CPI Log	Good clean sandstone, very high N:G, fining up, common sharp base	Coarsening up	Thin, no porosity or permeability
Sandstone Geometry	Channel	Sheet	
Depositional Environment	Distributive channels cutting delta	Bayhead delta	Ichron: Bay environment (Ichron)

			Back barrier lagoon with micro-tidal system (Dundas)
Mean Porosity	0.192	0.164	0.066
Mean Permeability	445.5	2.533	0.78
Typical Formation	Ness	Ness	Ness
Reservoir/ Non Reservoir	Reservoir	Reservoir	Non reservoir

Table 3- Facies Associations typical core expressions and depositional environment

3.1.2 Facies Interpretation of CPI Logs

Facies associations have been interpreted on all fip3 CPI logs (Appendix).

3.1.3 Fluvial Channel Geometry

Measured thicknesses and interpreted widths of distributary channels and multi-storey fluvial channels types A and B are shown in Table 4 below.

Dundas)2014) Facies Association	**Gibling (2006) Name**	**Dimensions in Literature**	**Measured Thickness**	**Estimated Channel Width**
Single and Multi-storey fluvial channels A and B	Delta distributaries	Thickness (T) 1-35m; most <20m; common range 3-20m Width (W) 3m-1km; most <500m; common range 10-300m W/T 2-345; most <50; many <15; common range 5-30 (Gibling 2006)	Multi-storey type B (ft)/ (m) Range: 4-25ft/ 1.2- 7.62m Median: 9ft/ 2.74m Mean: 10.28ft/ 3.1m Mode: 7ft / 2.1m Multi-storey type A Range: 3-11ft/ 0.91-3.35m Median: 5ft/ 1.52m Mean: 5.74ft/ 1.75m Mode: 4ft/ 1.2m Measured Ts fit common Gibling (2006) range.	Range estimated at 10-300m W/T common range 5-30
Distributary channel	Distributary channel/ valley fill (incised fluvial to estuarine complex)	Width-thickness ratios for fluvial distributary channel reservoirs are on average 50:1 (Pavenberg 2003)	Range: 26-85ft/ 7.9-25.9m Median: 35ft/ 10.6m Mean: 42.2ft/ 12.86m Mode:35ft/ 10.6m Thicknesses typical of distributary channels	Range estimated at 395m-1295m

Table 4:Interpereted dimensions of fluvial channels in fip3

3.1.4 Rock Quality

Descriptions of rock quality for each well are included in the appendix. These are based on core data where available, CPI and composition logs and lithological descriptions (Amaco). A summary of rock quality and RFT data is provided in Figure 11.

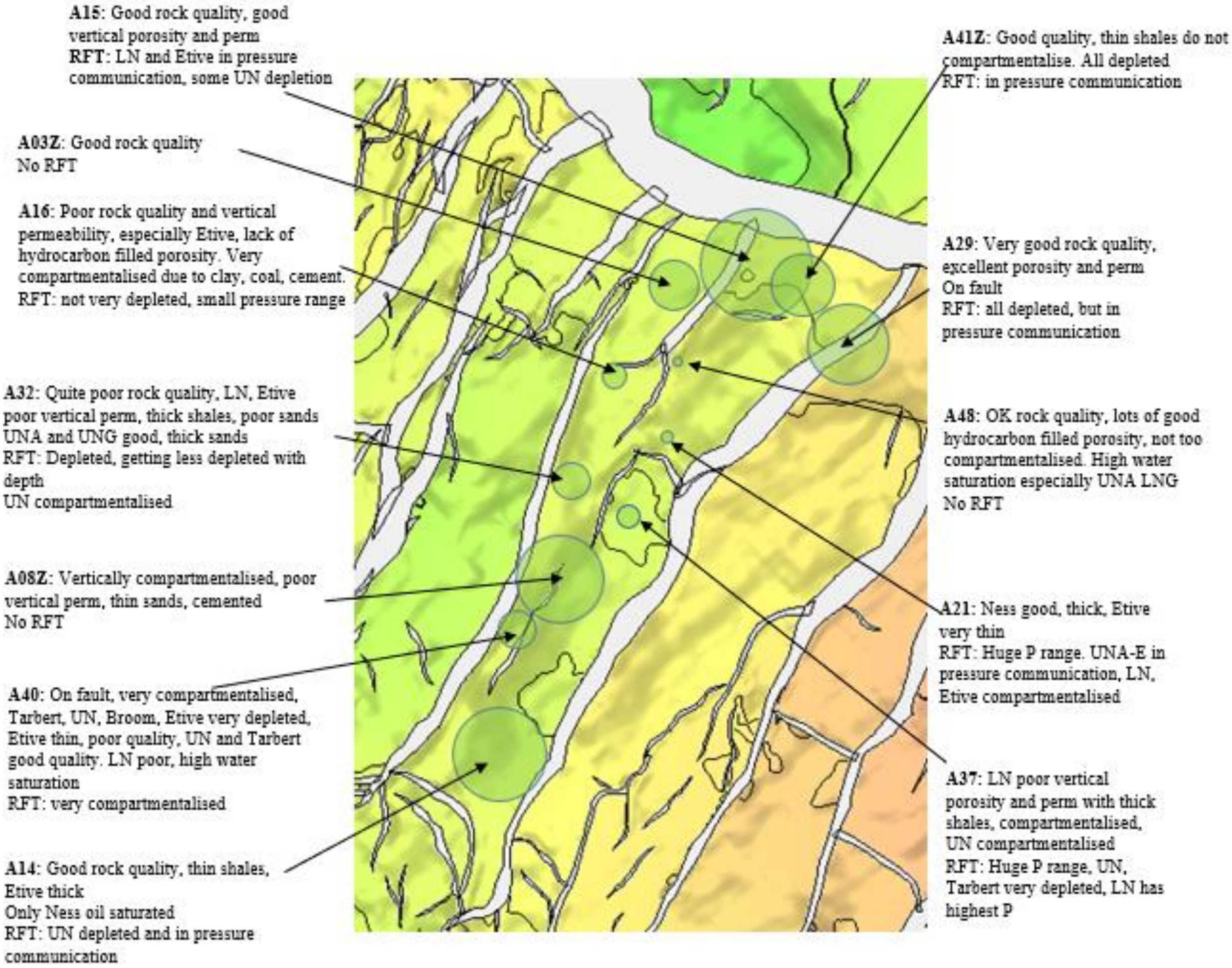


Figure 11- Summary of Rock Quality and RFT Data in fip3

3.1.5 Net Sandstone Thickness

Table 5 (below) displays calculated net sandstone thickness (ft) for each well. Figure 12 displays a map with net sandstone thickness represented by area.

Well	**Net Sandstone Thickness**
A03Z	259ft
A08Z	478ft
A14	606ft
A15	479ft
A16	225ft
A21	33ft
A29	180ft
A32	270ft
A37	288ft
A40	306ft
A41Z	285ft
A48	340ft

Table 5: Net Sandstone Thickness of Wells in fip3

Overall wells with a higher net sandstone thickness have a higher cumulative oil production. A08Z, A14 and A15 have high net sandstone thickness and high cumulative oil production. A16, A32, A37, A40 and A41Z also fit this trend. Some wells do not fit this trend; A29 has the lowest N:G but the 4th highest cumulative volume of oil. A03Z also has a low net sandstone thickness and a medium cumulative oil volume. A29 has a relatively high net sandstone thickness but the 2nd lowest cumulative oil. A48 also has a high net sandstone thickness but a low cumulative oil volume.

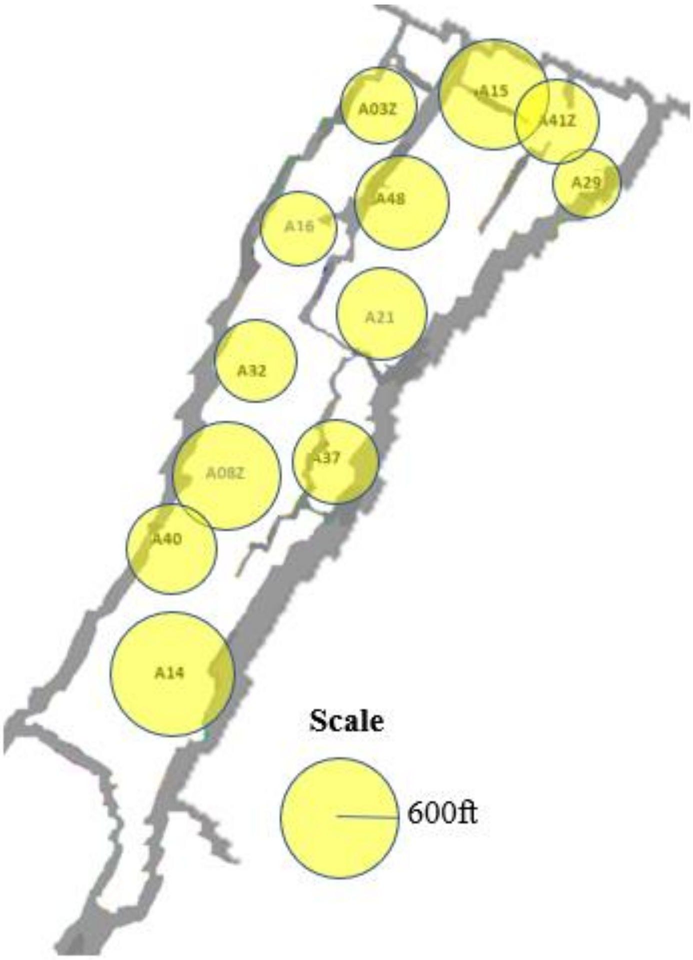


Figure 12- Net sand thickness (ft) in fip3. Area of circle is representative of net sand thickness

3.1.6 Log Correlation

Log correlations of each unit have been completed using Petrel and are displayed in the Appendix.

3.1.7 Isopach Maps

Isopach maps indicating the thickness of each unit are displayed below (Figures 13-32). These are based on the geological dataset of well top data (provided by Bridge Petroleum), for depths (TVDSS in ft) of the tops of the Broom Formation, Rannoch Formation, Etive Formation, LNA-G, MNS, UNA-G and the Tarbert Formation for each of the wells in fip3. Using Petrel, automated contours were drawn between data points and thickness variations of layers across fip3 were calculated. The scale varies between each isopach map in order to show the variation of thickness in every unit.

The accuracy of the isopach maps depends on the quantity and quality of the thickness data. There are only 12 data points in fip3 (one per well) and variations of thickness between datapoints, for example created by faults or channels, were not taken into consideration when plotting the maps. Therefore, the isopach maps will be more accurate for laterally extensive units like the Etive Formation rather than the Ness Formation which is made up of many thin, coalescing channels.

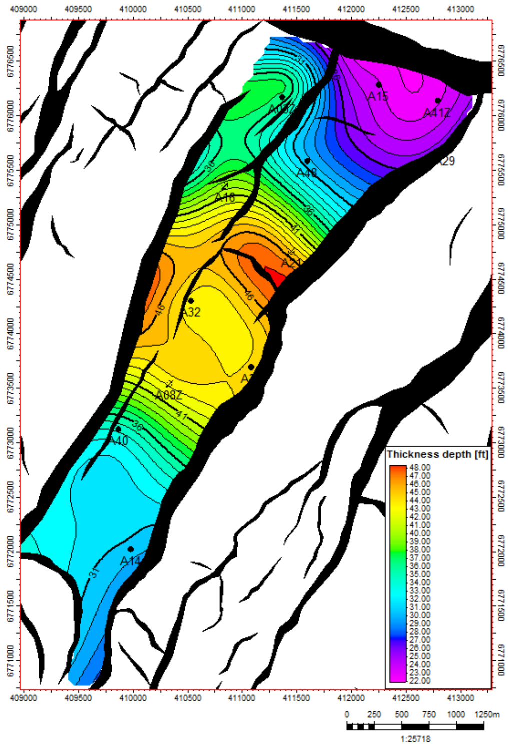


Figure 13- Isopach Map of the Broom Formation

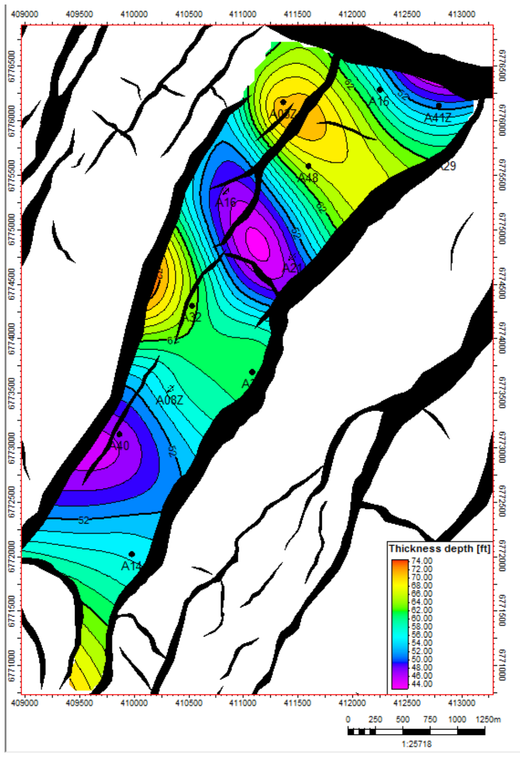


Figure 14- Isopach Map of the Rannoch Formation

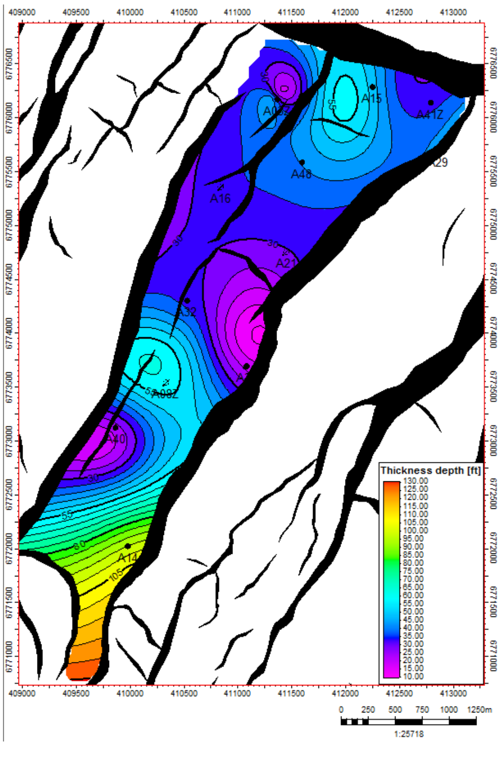


Figure 15- Isopach Map of the Etive Formation

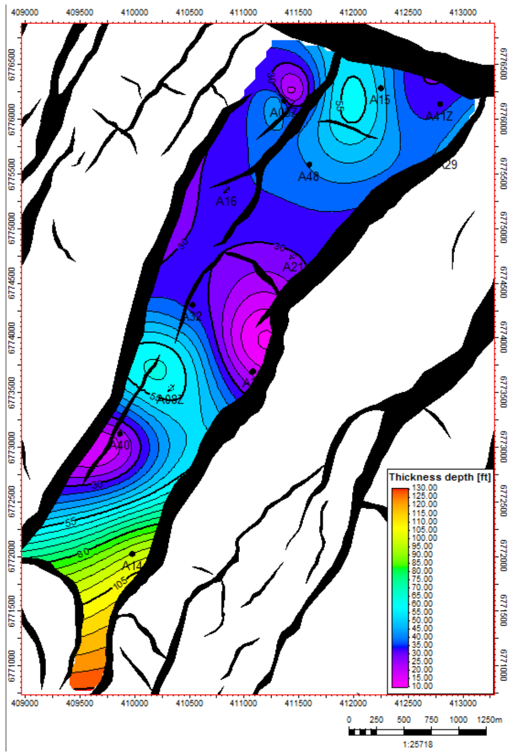


Figure 16- Isopach Map of LNA, Lower Ness Formation

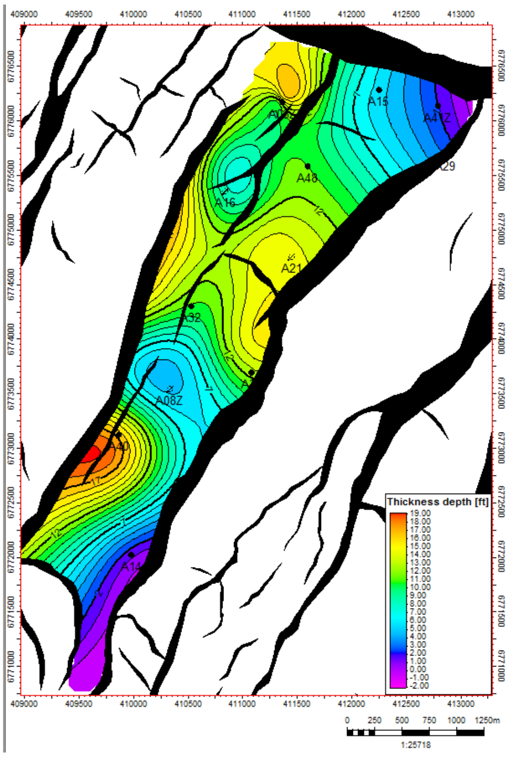


Figure 17- Isopach Map of LNB, Lower Ness Formation

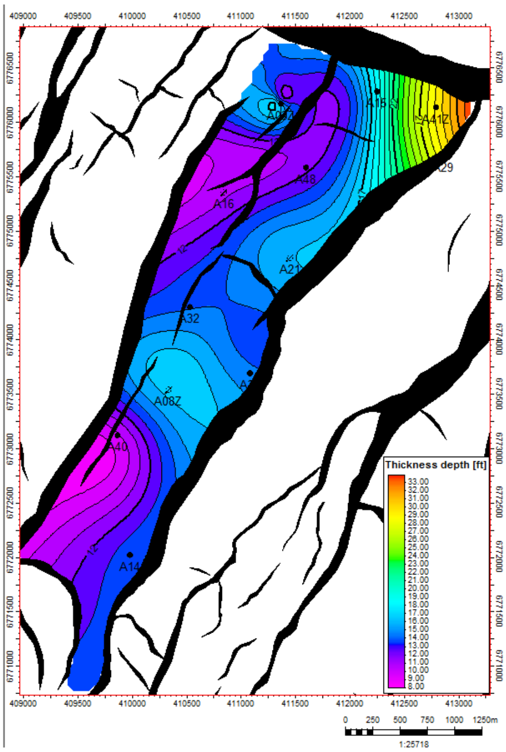


Figure 18- Isopach Map of LNC, Lower Ness Formation

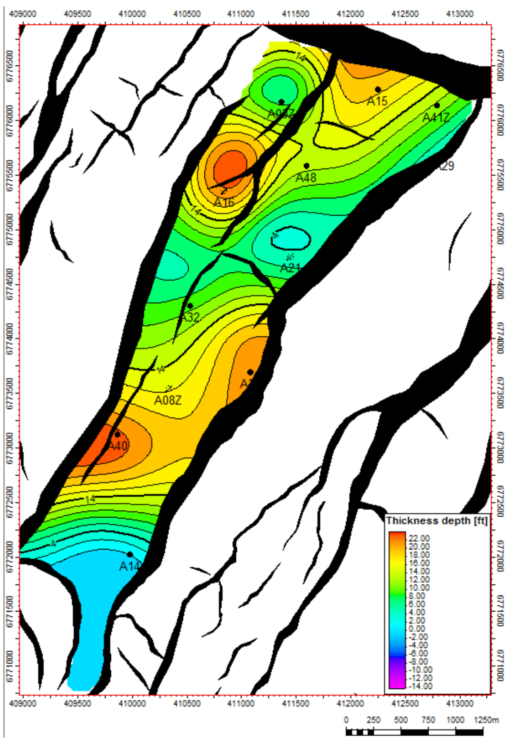


Figure 19- Isopach Map of LND, Lower Ness Formation

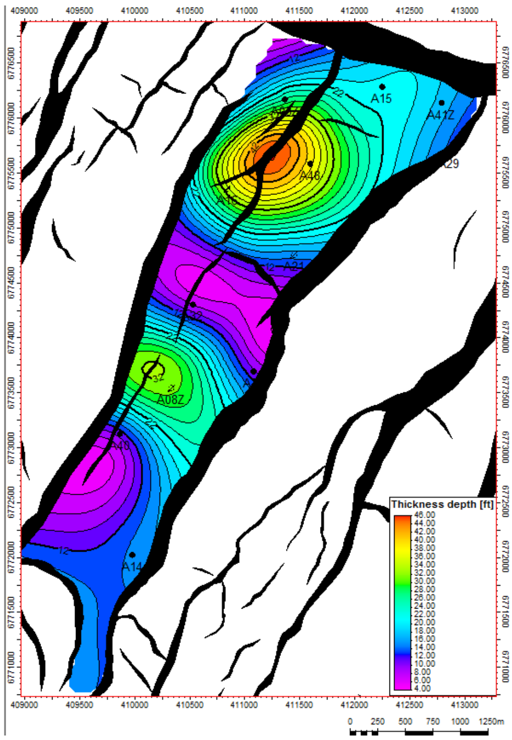


Figure 20- Isopach Map of LNE, Lower Ness Formation

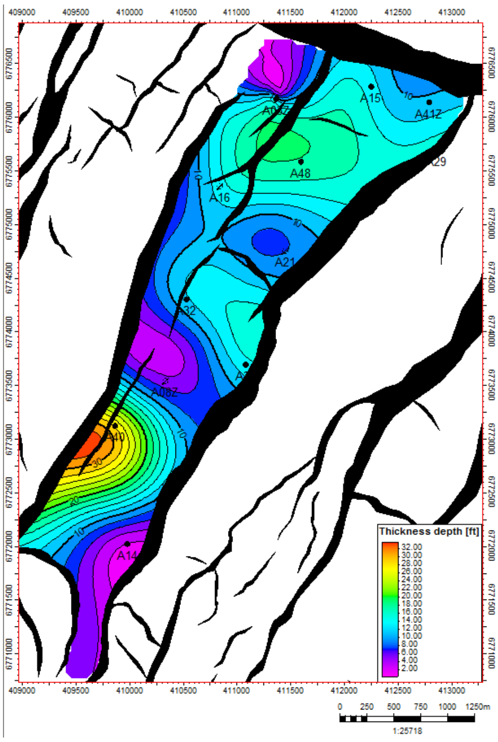


Figure 21- Isopach Map of LNF, Lower Ness Formation

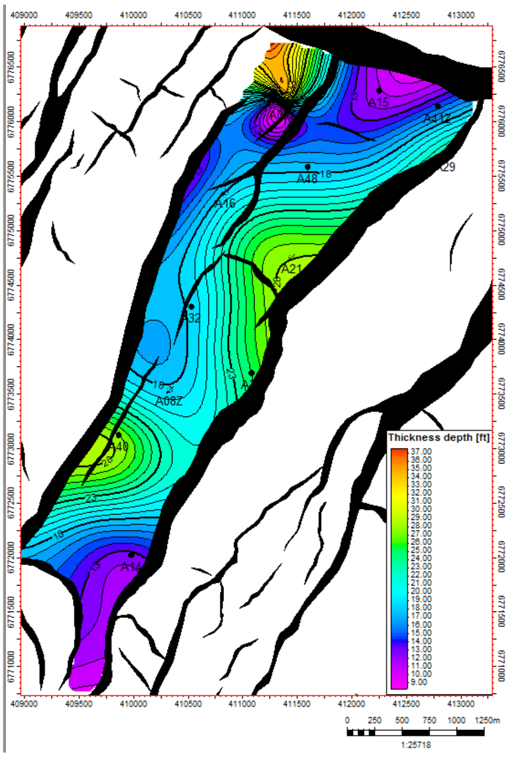


Figure 22- Isopach map of LNG, Lower Ness Formation

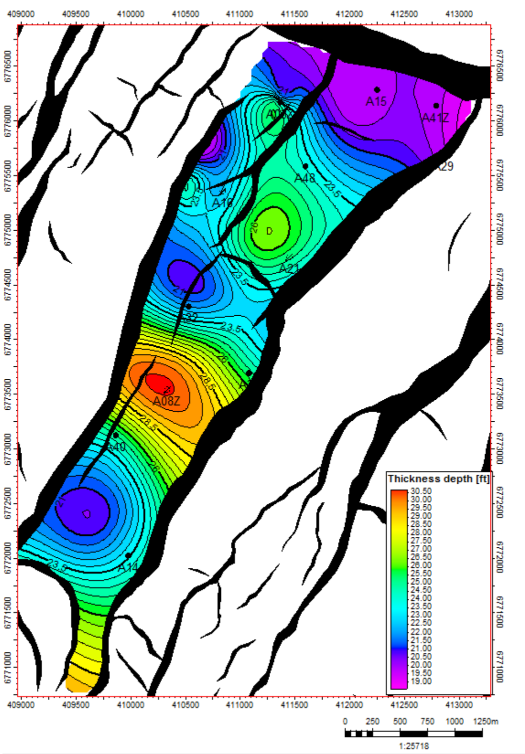


Figure 23- Isopach Map of the Mid Ness Shale

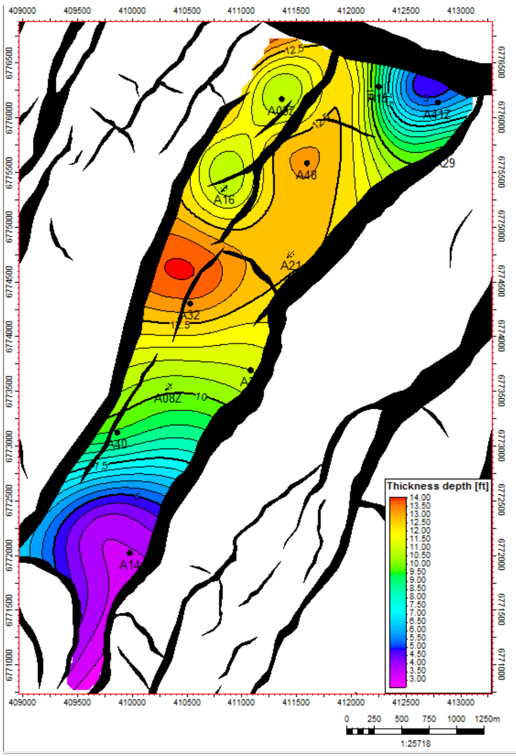


Figure 24- Isopach Map of UNA, Upper Ness Formation

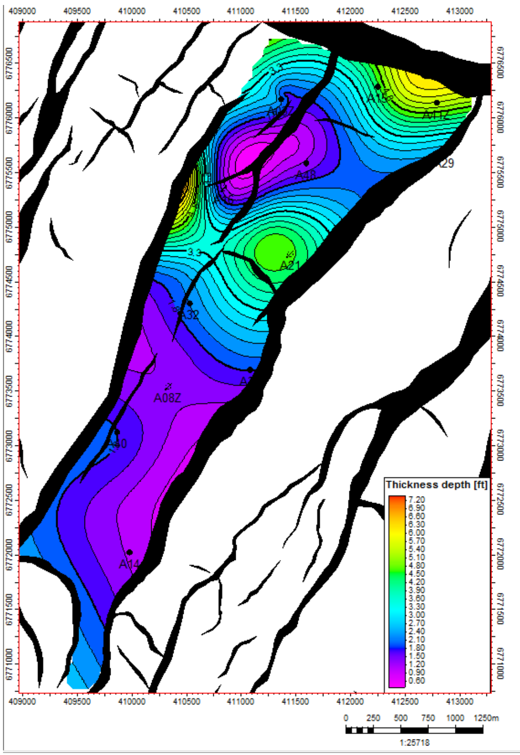


Figure 25- Isopach Map of UNB, Upper Ness Formation

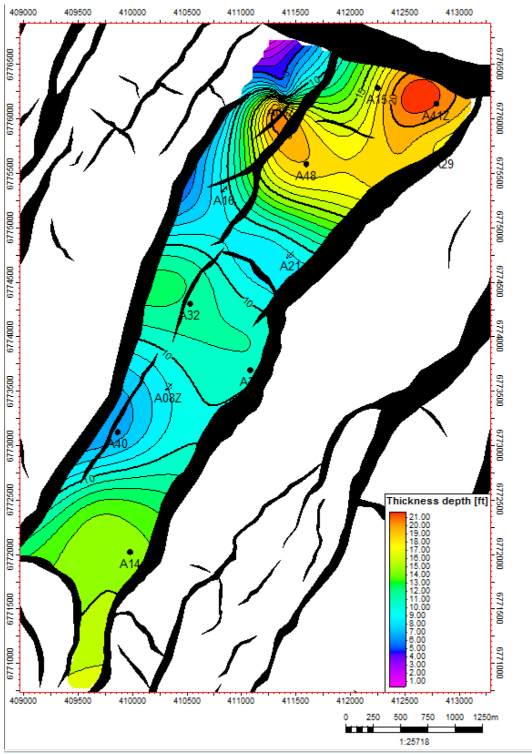


Figure 26- Isopach Map of UNC, Upper Ness Formation

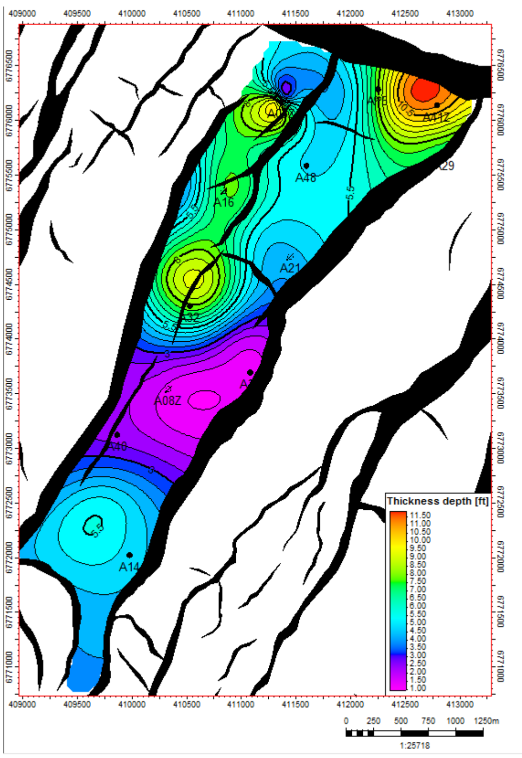


Figure 27- Isopach Map of UND, Upper Ness Formation

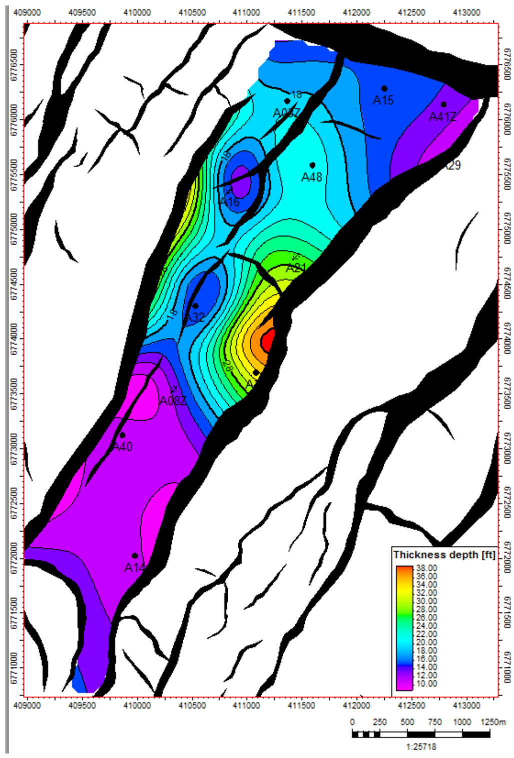


Figure 28- Isopach Map of UNE, Upper Ness Formation

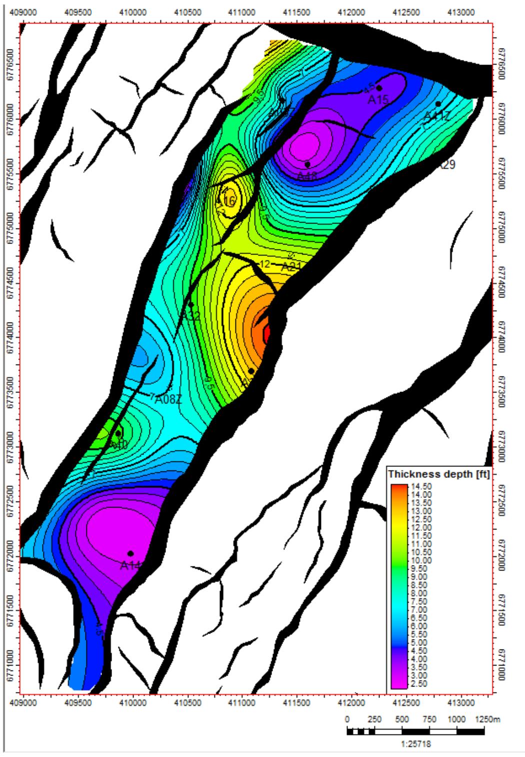


Figure 29- Isopach Map of UNF, Upper Ness Formation

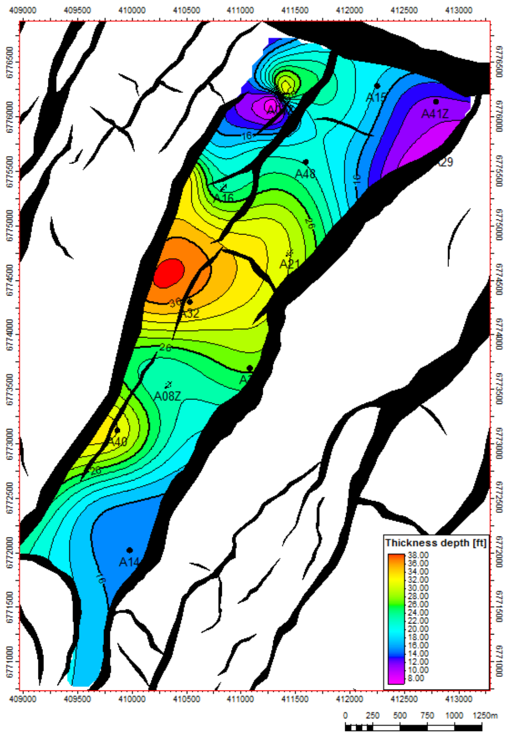


Figure 30- Isopach Map of UNG, Upper Ness Formation

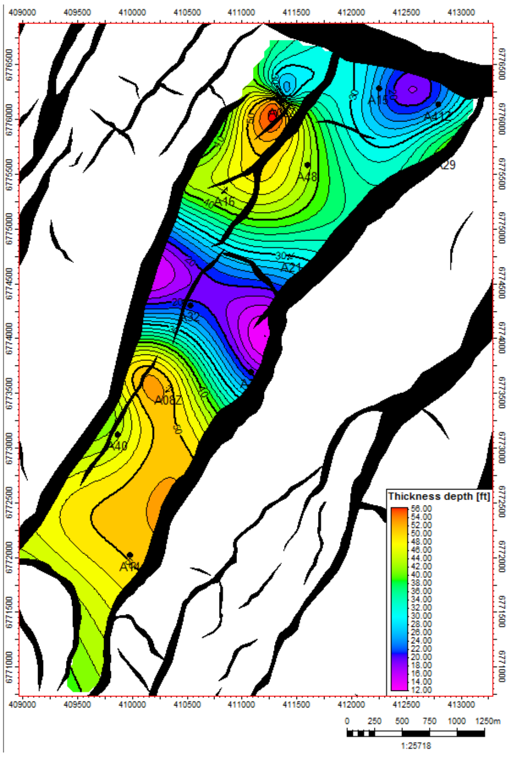


Figure 31- Isopach Map of Top UN, Upper Ness Formation

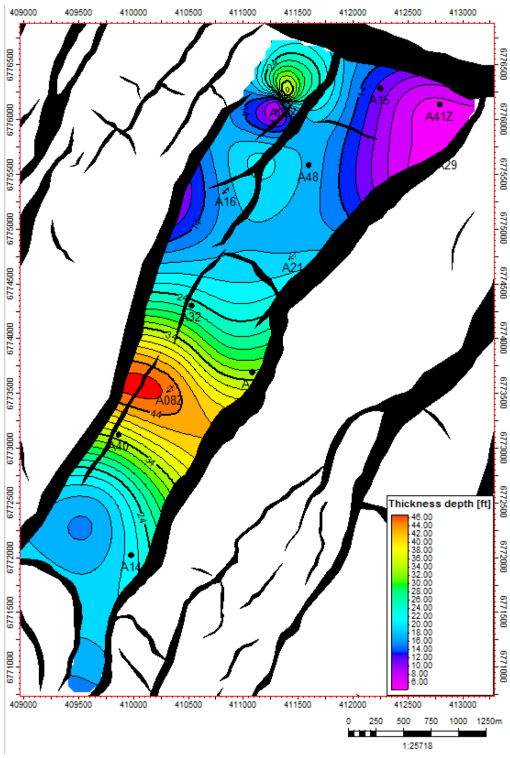


Figure 32- Isopach Map of the Tarbert Formation

3.1.8 Porosity and Permeability

3.1.8.1 Porosity and Permeability by Formation

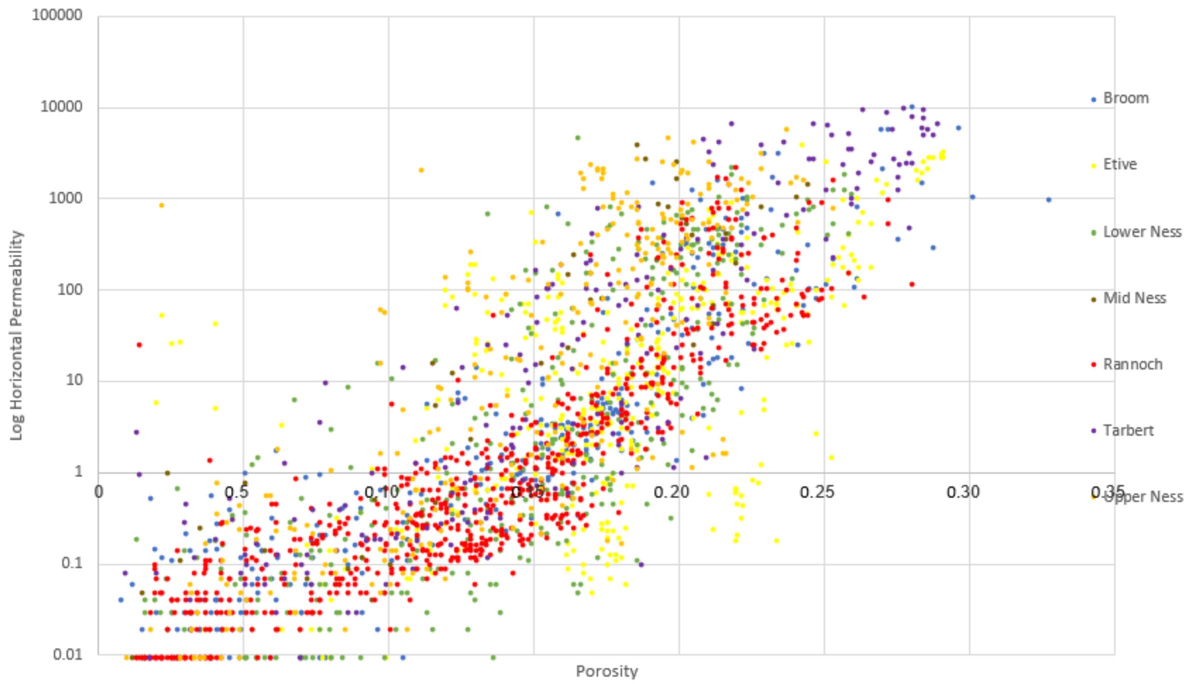


Figure 33- Porosity and Permeability by Formation

Figure 33 shows a positive correlation between porosity and log permeability. The Broom Formation is spread out, with a cluster of low permeabilities and porosities. The Rannoch Formation shows a tight linear trend, with porosities and permeabilities generally relatively low. The Etive Formation has high porosities and permeabilities. The Ness Formation show 2 main clusters of both very high and very low permeabilities and porosities. The Tarbert Formation has very high permeabilities and porosities.

3.1.8.2 Porosity and Permeability by Facies Associations

Facies Association	Porosity	Standard Deviation	Permeability	Standard Deviation
Distributary channel	0.201	0.034285	140.6	202.3491
Fluvial channel type B	0.192	0.031044	445.5	624.6238
Tidal shoal	0.187	0.046245	202	198.6466
Bayhead delta distal	0.164	0.057186	2.533	15.93534
Middle shoreface	0.144	0.068162	96.69	227.2828
Fluvial channel type A	0.142	0.070525	8.257	19.16025
Lower shoreface	0.138	0.037689	0.574	0.384549
Fluvial floodplain with crevasse splay sand bodies	0.119	0.042052	6.896	24.09763
Transition zone	0.093	0.048901	0.673	1.096268
Bay margin heterolithic	0.117	0.072921	2.291	4.307548
Fluvial floodplain mud rocks	0.105	0.025166	0.153	0.120381
Bay margins	0.066	0.02579	0.78	1.102225

Table 6- Porosities and Permeabilities of Facies Associations, with standard deviations

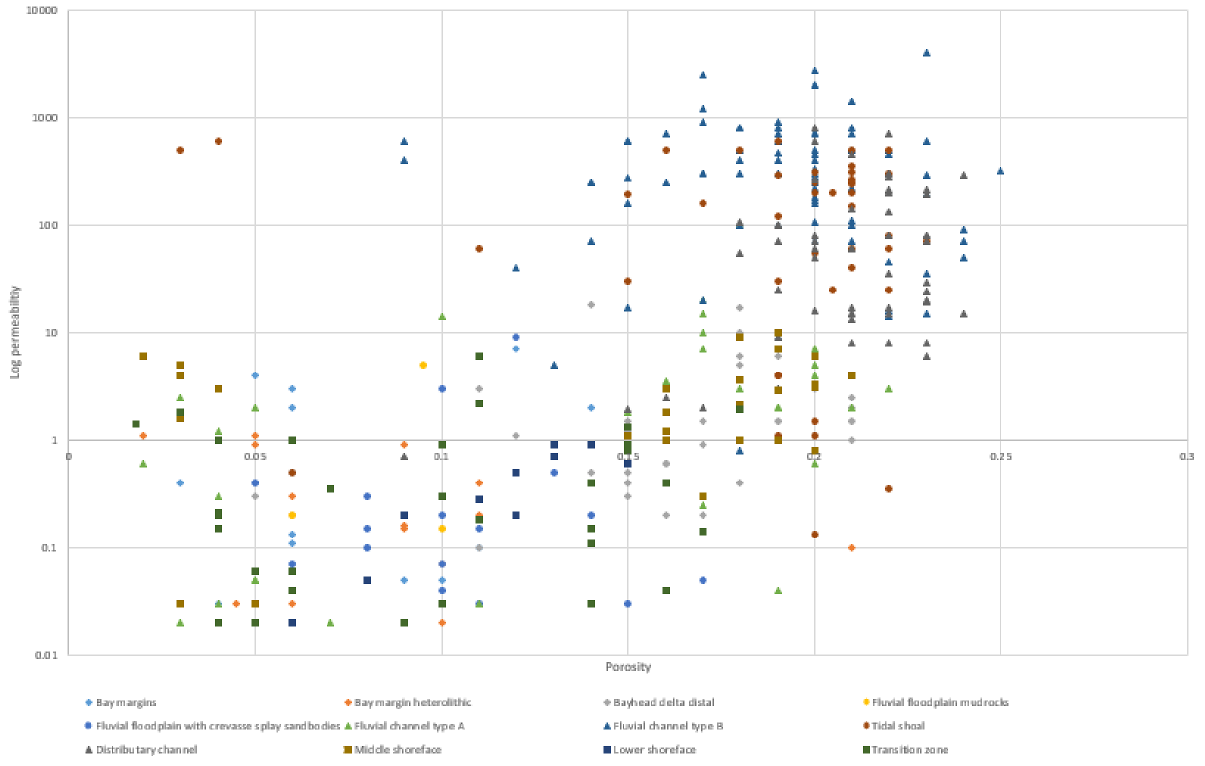


Figure 34- Porosity and Permeability grouped by Facies Association

Figure 34 shows porosity and permeabilities grouped by facies associations. Permeability and porosity by facies association are summarised in Table 6.

Overall there is clearly some relationship between facies associations and reservoir porosity and permeability trends. Significant groupings are not obvious, there is of overlap of porosity and permeability values between facies associations.

Fluvial channel type B has the highest porosities and permeabilities, followed by distributary channel facies associations.

Fluvial channel type A has lower permeabilities but only slightly lower porosities than the other channel bodies. There are 2 clusters- one with higher permeability and porosity, one with lower. middle shoreface shows a similar trend.

Tidal shoals have consistently high permeabilities, generally over 20mD, but porosity varies from 0.035-0.225. Bayhead delta porosities are mid- higher range, with the main cluster between 0.13 and 0.22, and mid-range permeabilities between 0.1-10mD. Bay margins have low permeabilities and porosities.

From middle shoreface, lower shoreface to transition zone permeability and porosity decreases in a linear fashion. The transition zone cluster is spread out.

Bay margin heterolithics have low porosity and permeability. More porosity and permeability data is required to show the full extent of heterolithics. Fluvial floodplain with crevasse splay sandstones are low permeability and porosity with a few high permeability and porosity datapoints. Fluvial floodplain mud rocks have low porosities <0.1, and permeabilities <8mD.

3.1.8.3 Porosity and Permeability of Reservoir Sandstone Facies Associations

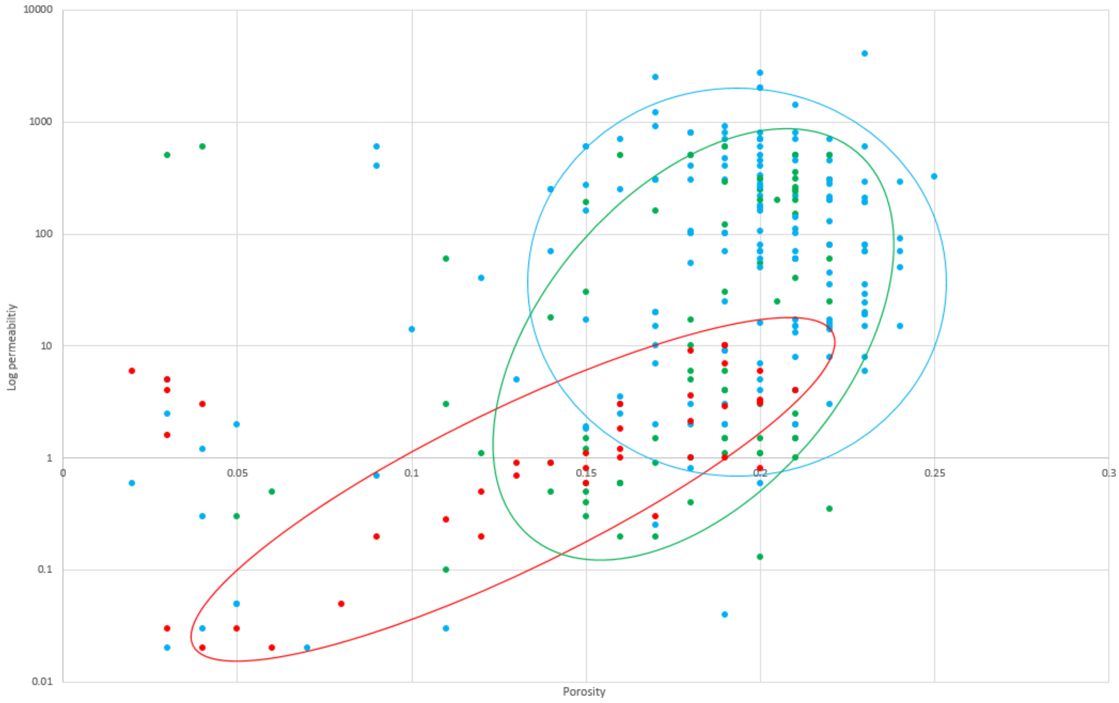


Figure 35- Porosity and Permeability of Reservoir Sandstone Facies Associations

Mudstones and coals are omitted and only reservoir quality sandstone facies associations are displayed in Figure 35, the plot of porosity versus log permeability.

Facies associations can be rationalised into 3 groups showing clustering of

- Sandstones deposited in tidally influenced settings (tidal shoal, bayhead delta) (red)
- Middle and lower shoreface sandstones (green)
- Fluvial channel sandstones (blue)

There is a clear relationship between depositional facies association and reservoir quality. Fluvial channel sandstones have the highest permeabilities and porosities. Middle and lower shoreface sandstones also have high permeabilities and porosities but with a less defined cluster due to common mid-level porosities and permeabilities. Sandstones deposited in a tidally influenced settings show a linear trend and include mid-range and very low porosities and permeabilities.

3.2 Structure

3.2.1 Well elevations

Well elevations in true vertical depth sub-sea (TVDSS) are shown in the appendix. Wells to the west of fip3 are more deeply buried due to the fault blocks dipping in that direction. A14 to the south of fip3 is deeply buried.

3.2.2 Oil Water Contacts (OWC)

Interpretations of OWC's (Table 7) were based off water saturation data on CPI logs (Appendix). Where the OWC is not visible water up to / oil down to (WUT/ ODT) data are used and where all the Brent Group is oil saturated, the OWC is interpreted below base Brent. Bridge Petroleum values were compared to these values.

Well	OWC/ ODT	Bridge values
A03Z	ODT 14975 WUT 14978	
A08Z	ODT 16020, WUT 16095	ODT 16020 MD
A14	ODT 18727, WUT 18760	
A15	Below base Brent	
A16	ODT 14450, WUT 14480	ODT 14429, WUT 14479
A21	ODT 15900, WUT 15920	
A29	Below base Brent (faulted out to LN)	
A32	ODT 14958, WUT 14960	ODT 14948, WUT 14958
A37	ODT 16504, WUT 16532	ODT 16566, WUT 16572
A40	ODT 16025, WUT 16040	
A41Z	Below base Brent	
A48	OWC 15824	

Table 7- OWCs/ODTs in fip3

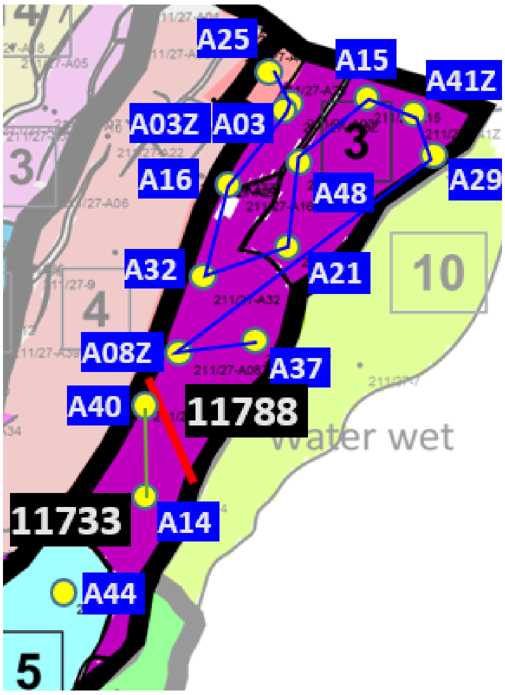


Figure 36- OWC Interpretation (red line) for fip3 (Bridge Petroleum)

OWCs in this study are similar to the results from Bridge Petroleum. The OWC in fip3 (Figure 36) was interpreted by Bridge Petroleum in the south (11733ft), segregating A40 and A14 from other wells to the north (11788ft). Reasons for the difference in contact in the south are unclear, it is possible that stratigraphic elements are at play after a structural syncline (Bridge Petroleum).

3.2.3 Depth Structure

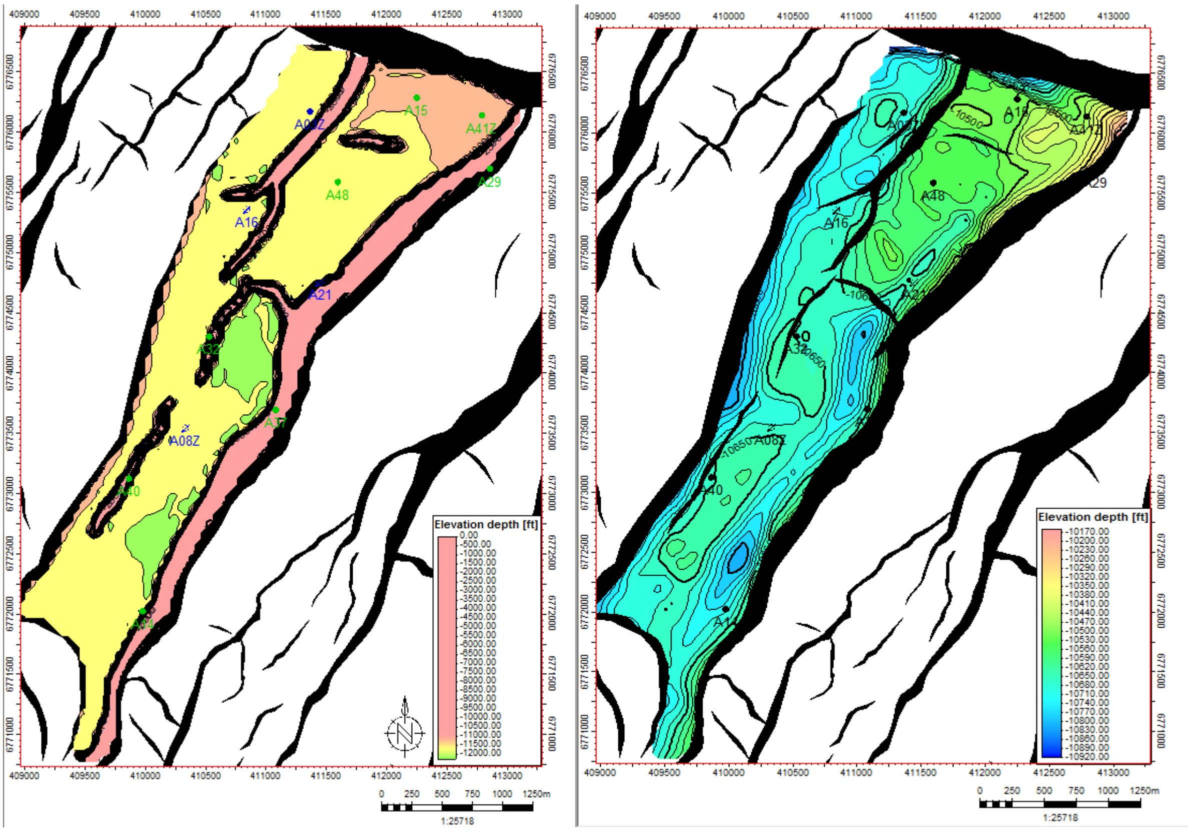


Figure 37- Depth Structure Maps with and without Fault Polygons

Depth structure maps have been created in Petrel, both with Brent Group interval fault polygons and without (Figure 37). Both show a structural low to the SE of fip3, where the OWC has been interpreted (Bridge Petroleum).

3.2.4 Repeat Formation Tester (RFT) Data

No repeat formation tester (RFT) data is available for A03Z, A08Z or A48.

Pressure range per well and for each layer are provided in Tables 8 and 9 respectively. RFT graphs (Bridge Petroleum) are in the appendix.

Well	Lowest Pressure (psi)	Highest Pressure (psi)	Pressure Range (psi)
A14	6622.7	7607.7	985
A15	6706	7228	522
A16	5967.7	7063.7	1096
A21	2722.7	7212.7	4490
A29	3443.7	4257.7	814
A32	2175.7	7666.5	5490.8
A37	2078	8676	6598
A40	1779.7	7061.7	5282
A41Z	4510.3	6024.2	1513.9

Table 8- Pressure ranges in fip3, from RFT

The wells with the largest pressure ranges are A21, A32, A37 and A40 with ranges >4000psi. These wells are located towards the centre of fip3.

The wells with the smallest pressure ranges are A14, A15 and A29, with ranges <1000psi. These wells are at the northern and southern ends of the fip3, A14 and A29 are located on faults.

A14, A15 and A16 all have high pressures but a small range, indicating they may be less depleted.

The Tarbert Formation is generally the most depleted layer, and pressures increase with depth.

Well	**Date**	**Tarbert**	**UNG**	**UNF**	**UNE**	**UND**	**UNC**	**UNB**	**UNA**	**LNG**	**LNF**	**LNE**	**LND**	**LNC**	**LNB**	**LNA**	**Etive**	**Rannoch**	**Broom**
A14	20/5/1984		6622.7-6626.7		6620.7		6627.7	6634.7		7391.7							7397.7-7607.7		
A15	25/4/1984		6891-7265		6837		6706		6715	7140		7149-7150		7179-7185			7225-7228		7099-7103
A16	10/6/1984		6236-6814		6278.7		6317.7		5967.7	6227.7-6234.7		6244.7-6596.7					6923.7		6996.7-7063.7
A21	25/1/1985	2722.7	4656.7-5080.7		4226.7		4228.7		4244.7	3538.7		6622.7		7212.7			4253.7-4707.7	4800.7	4695.7
A29	20/1/1986				4088.7		4107.7-4125.7		4257.7			3443.7-3444.7							
A32	5/10/1987	2175.7	6023.7-6053.9				4417.5	4417.5	5848.2-5881	5269.2							6504-6545		7599.5-7666.5
A37	17/8/1988	2078	3603.5		3684		5733.7		4558.4		8676	8586.7					6484.4		6106.5-7297.5
A40	20/7/1989	1779.7	2362.7-2730.7				2857.7		3062.7	3758.7		6520.7		7061.7			5548.7		6404.7
A41Z	9/2/1991	4510 .3			4871.7		4853-4864		5007.4	4872.1-4873.5		4880.3-4885.6	4887.2	4886.9-4890.5		6016	6021.1-6024.2		5604.Table 11-4-5608.4

Table 9- Pressure (PSI) per unit

3.2.5 Production Logging Tool (PLT) Data

PLT data is in shown in the appendix. Producing units per well have been summarised into Table 10 (below).

The Broom Formation produces only in A15 and A16. The Rannoch Formation only produced in A21 and only the top of the Formation produced.

The best oil producers were the Etive Formation, LNG and UNA. The Etive Formation produced in all wells except A14, A29 (where it is faulted out), A37, A40, A41Z, A48. The LNG produced in all wells but A08Z, A37, A40, A41Z, A48, and UNA in all except A37.

The Tarbert Formation produced in all wells but A14, A29, A32, A37.

Well	Producing layers	Layers flowing together
A03Z	Tarbert, UNA-C, LNG, LNE-F, Etive	UNG started separately then UND-upper UN flowing as one
A08Z	Tarbert, UNG (tiny), UNE-F, UNA (good), LNA-D, Etive	UNE+UNF, LNA-D
A14	UNE-G, UND, UNA-C, LNG	UNE-G, UNA-C
A15	Tarbert, UNE-G, UNC, UNA, LNG, LNE-F, Etive, Broom	LNA-E flowing as one, not much production Layers in UN quite separate
A16	UNF-G, UNE, UNB-D, UNA (all of UN producing), LNG,LNE-F, Etive, Broom	UNF-G, UNB-D, LNE-F
A21	Tarbert, UNG, UNE, UNC, UNA-B, LNG, LNE-F, Etive/ top Rannoch	UNA-B, LNE-F
A29	top UN (small), UNE-G, UND, UNC, UNA-B, LNG	UNE-G, UNA-B
A32	UNG (lots), UNF, UNE,UND, UNB, UNA (lots), LNG,LND-F, Etive	LND-F
A37	UNF-G, UNC, LNE-F	UNF-G producing as a layer at first then UNF stops
A40	Tarbert, UNG, UNC, UNA-B, LNA-F (v little)	LNA-F
A41Z	Tarbert, UND-E, UNA-B,	UND-E, UNA-B
A48	Tarbert, UNE-G, UNA (little), LNE, LNA-E	UNE-G, LNA-E

Table 10: Producing units from PLT data

It is difficult to ascertain where sandstones produce together.

3.3 Production Data

3.3.1 Bubble Maps

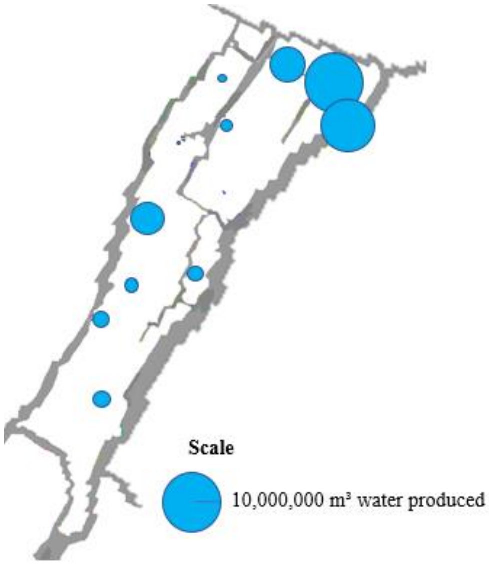


Figure 38- Bubble Map showing Cumulative Water Production of Wells in fip3

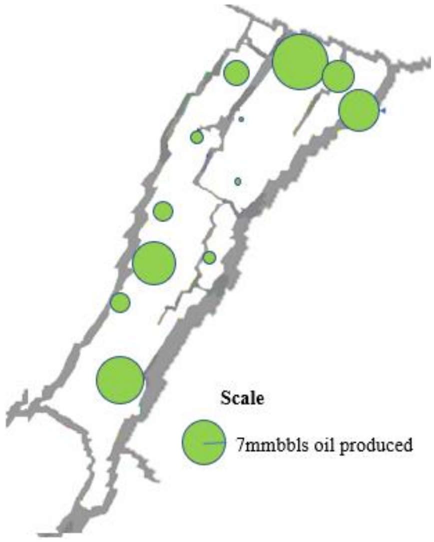


Figure 39- Bubble Map showing Cumulative Oil Production of Wells in fip3

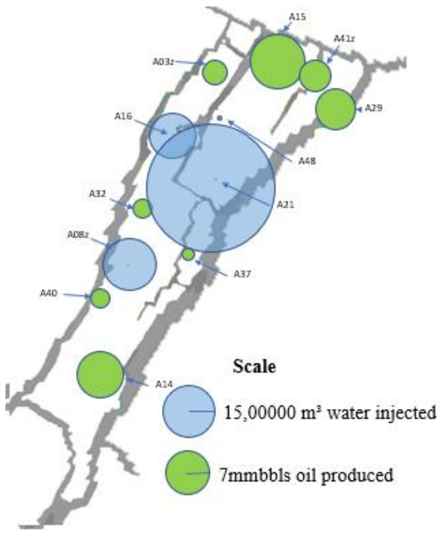


Figure 40- Bubble Map showing Cumulative Oil and Water Injection of Wells in fip3

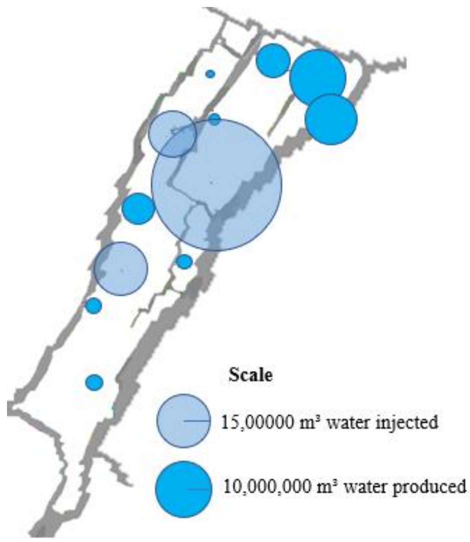


Figure 41- Bubble Map showing Cumulative Water Production and Injection of Wells in fip3

There was a high cumulative water and oil from A15, A29 and A41Z in the NE block, where A21 has the most water injection. A48 is also in this block but had low oil and water production despite being close to A21. A03Z had a low water production and was close to water injector A21. Injectors A16 and A21 produced little cumulative oil as they were producing for a short amount of time before they were converted to water injectors. A08Z had high oil production before it was converted to a water injector. A14 to the south had high cumulative oil but there is little water production in the south of fip3.Wells surrounding water injector A08Z (A32, A37 and A40) had low oil and water production. A37 in the fault block to the East of fip3 had very low water and oil production.

3.3.2 Water Injection

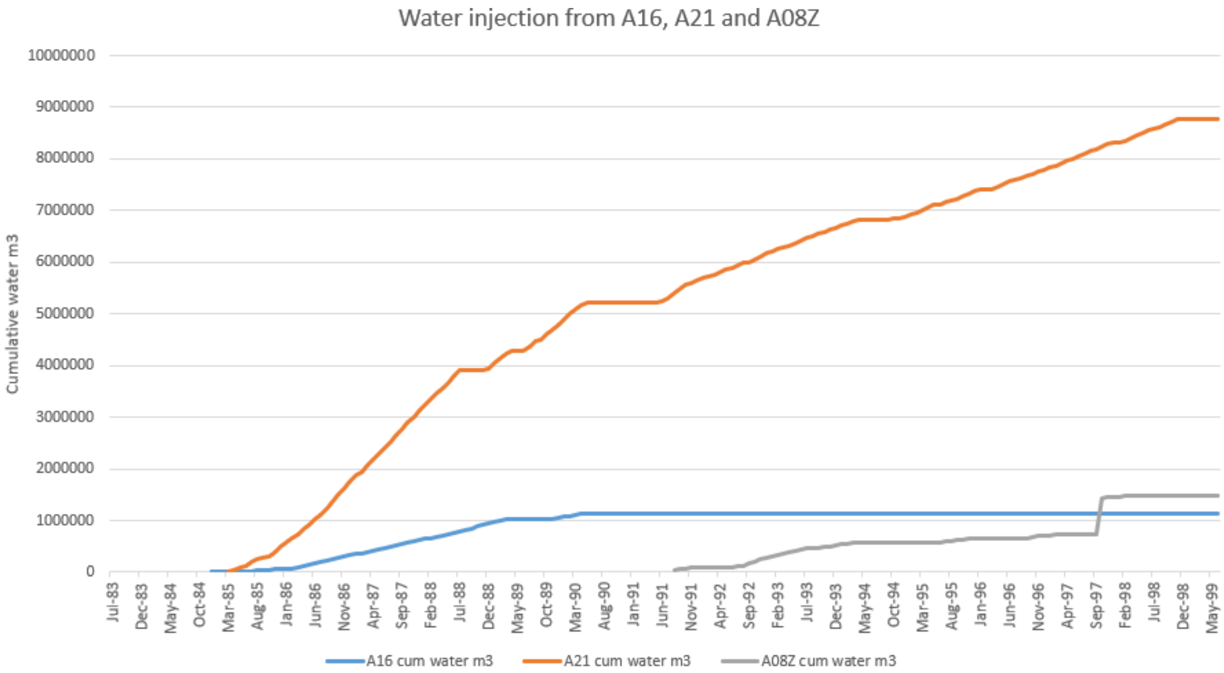


Figure 42- Cumulative Water Injection in fip3

Water injection was focused in the middle to north of fip3, with A21 in the NE block having produced the most water, and A08Z the least (Figure 42).

A16 and A21 were converted to water injectors in December 1984 and March 1985 respectively, and A08Z in August 1991. A21 injected the most water with a total of 87,74507 m^3. A08Z and A16 injected much less, at 14,92675 m^3 and 11,32518 m^3 respectively.

A21 had the highest initial water injection rate, which was maintained over a long period of time. The rate was fastest in the first 3 years. Injection then temporarily stopped in August 1988- December 1988, April 1989- June 1989 and April 1990- June 1991. After this water injection rate was slower but was steadily injecting until November 1998.

In A16 water injection slowed in March 1989 and stopped in April 1990.

A08Z had a slower but steadier rate of water injection, slowing gradually over time, then a sudden jump in September 1997, after which injection stopped.

3.3.3 Cumulative Oil Production

Clear trends can be seen from these data (Figure 43). Earlier wells, with the exception of A03Z had a higher starting oil rate which slowed in the last few months of production. The later wells had a slower rate of oil production which steadily increased.

The wells with the highest oil production are A08Z,A14 and A15 there is no clear geographical trend as they are in the centre, south and north of fip3.

Earlier wells, including A08Z, A14, A15, A16 and A29 have a higher cumulative oil production. Exceptions to this are A16 and A21, both converted to water injectors. A03Z had a similar cumulative oil production to later wells.

A41Z produced much more cumulative oil than other late wells, particularly A48, despite being in close proximity and beginning production at the same time.

A14 follows a different trend to other wells by steadily producing over a long period of time despite having a lower starting oil rate than other early wells. Oil rate increased in October 1990, at a similar time A32 also increased in oil rate. A41Z had another increase in oil rate in October 1996.

The sudden increase in A08Z water injection may correspond to another slight increase in A14 oil production around March 1998.

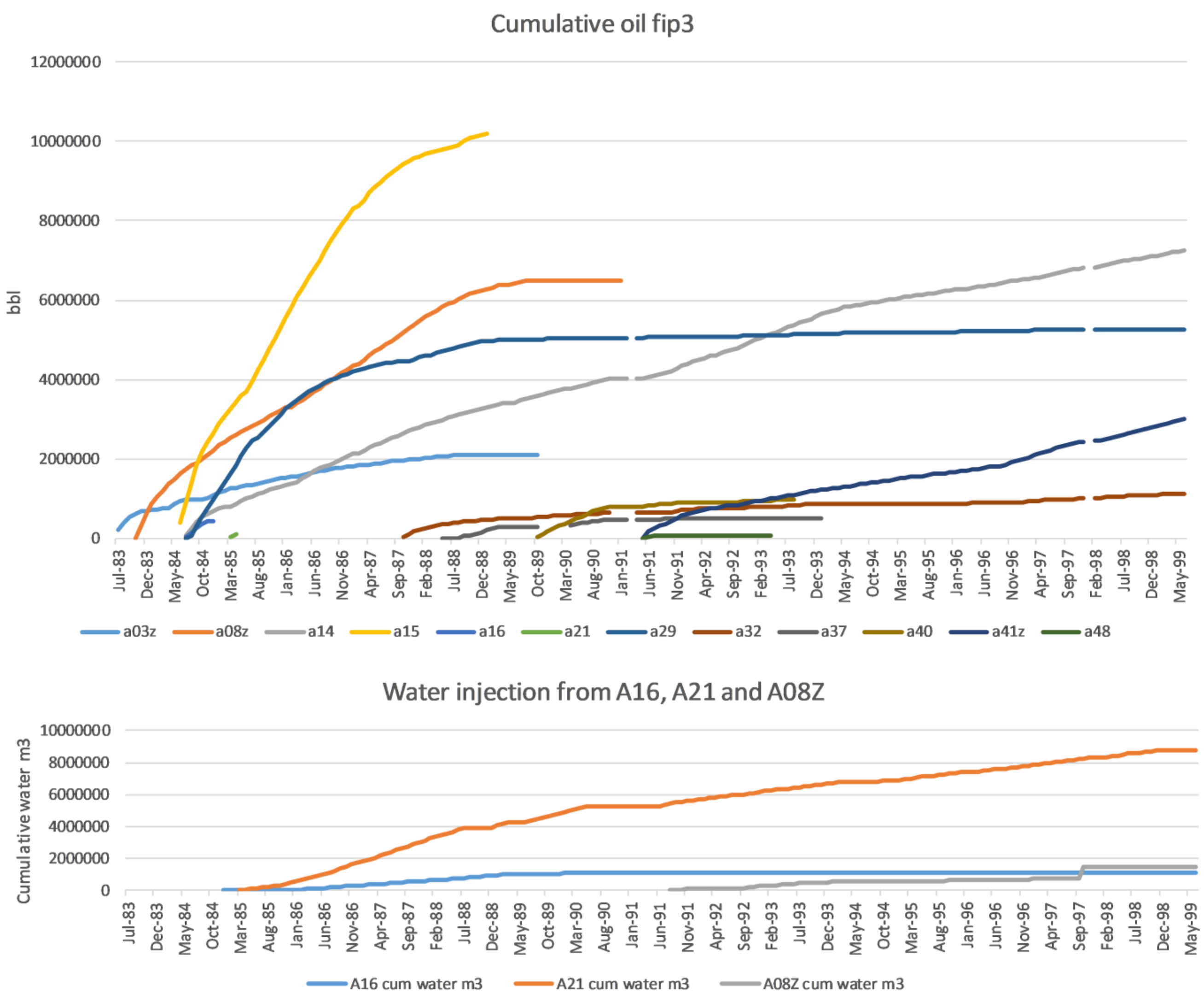


Figure 43- Cumulative Oil Production compared with Water Injection in fip3

3.3.4 Cumulative Water Production

There does not appear to be a temporal relationship between time of start production and cumulative water production (Figure 44).

The wells that produced the most water are A41Z, A29, A15 and A32. These all had rapid water production rates, with the exception of A32 which had a slow and steady build up of water production. A41Z produced a huge amount of water over a relatively short period of time. A29 water production rapidly slowed in October 1990 and January 1996.

The rate of water injection generally increased over time. There tends to be no to very little water produced at the start of the wells production, then water suddenly began production at a rapid rate. This was particularly evident in A15, A29 and A48. Water production rate tended to be high at the end of the wells production with the exception of A37, A48 and A03Z.

Water production slowly and steadily increased in A14 and A32, and water production rate slightly increased as A08Z begins water injection. In April 1995 A32, A14, A41Z and A29 all increased water production rate slightly.

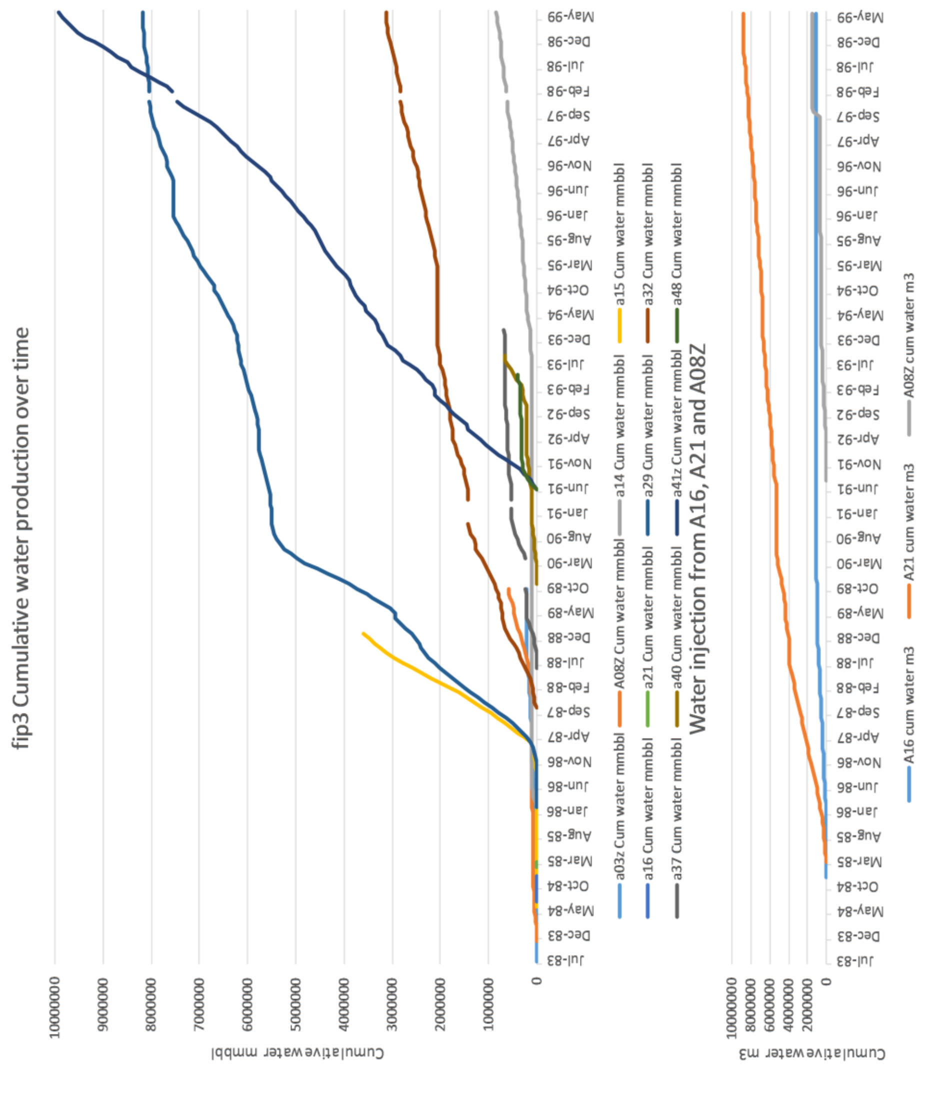


Figure 44- Cumulative Water Production compared with Water Injection in fip3

3.3.5 Oil Rate

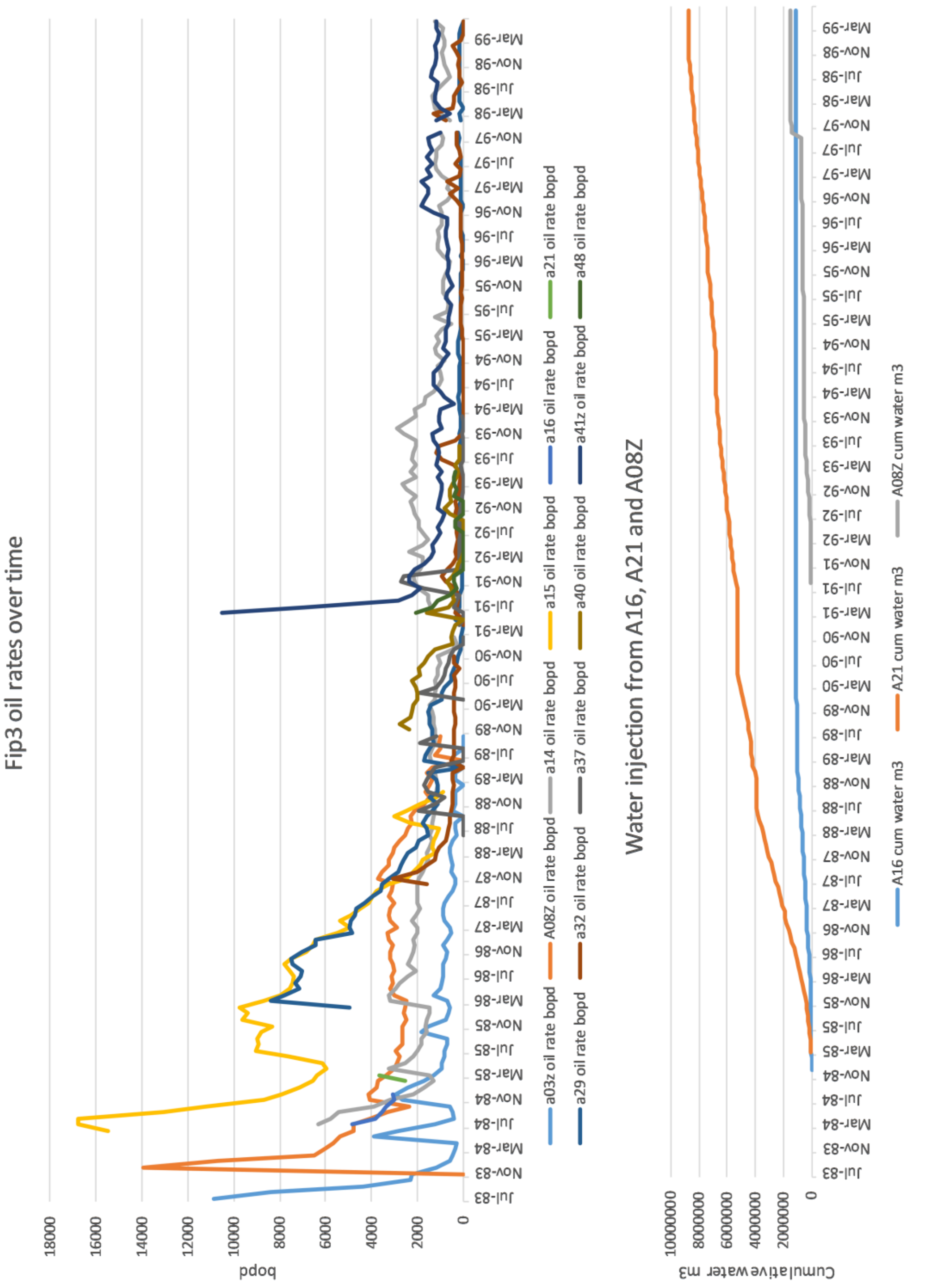


Figure 45- Oil Rate compared with Water Injection in fip3

Oil rate was highest in early wells A03Z, A08Z, A14, A15 (Figure 45). A41Z was an exception with a starting oil rate similar to these early wells despite coming onto production much later. It had a much higher oil rate than wells producing at a similar time.

Oil rate was initially high but rapidly dropped in wells A03Z, A08Z, A14, A15, A16, A29, A41Z, A48, sometimes punctuated with more, smaller, short term increases.

These increases in oil rate are most evident in A08Z (October 1984), A15 (April 1985), A03Z (April 1984), and A14 (February 1985), at similar times to the start of A21 (March 1985) and A16 (December 1984) injection.

3.3.6 Water Oil Ratio (WOR)

Water oil ratio (WOR) generally increased over time (Figure 46), some in some wells, such as A16 and A08Z, decreased before a rapid increase. Many wells show rapid increases in WOR.

There are 2 main trends; gradually increasing WOR such as A41Z and A37 or rapidly increasing WOR at the start of production A03Z, A08Z, A15, A29, A32, A40 and A48. There does not appear to be a clear link between geographical location and WOR trend. A14 has a different trend, WOR remained very low <1 despite a long time on production.

Later wells, such as A48, had higher starting WOR's. A48 had a similar starting WOR to the ending WOR of geographically close wells A29 and A15.

A29, A32, A37, A40, A48 all reach 20 WOR and 95% water cut.

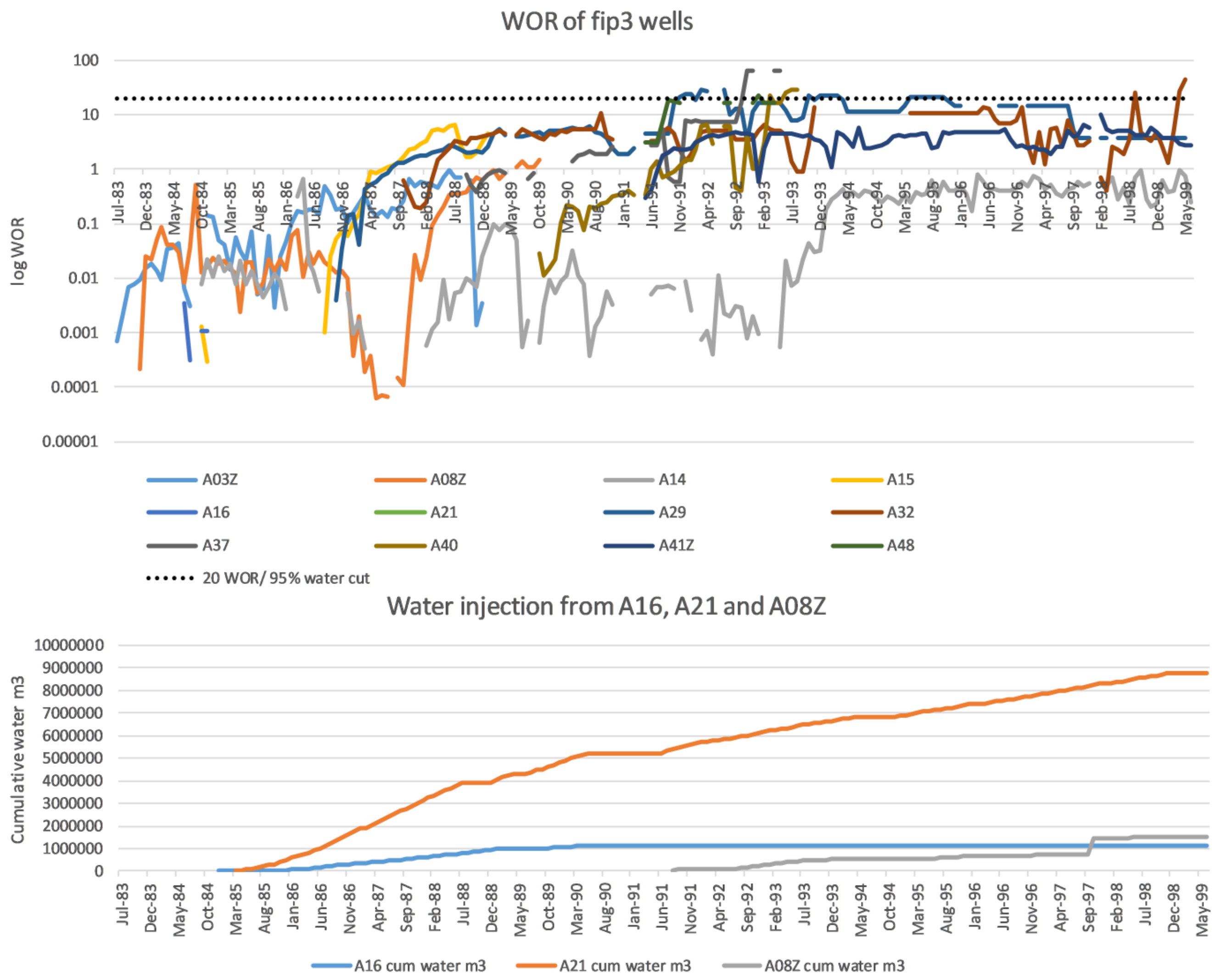


Figure 46- log WOR and Water Injection in fip3

3.3.7 Gas Oil Ratio

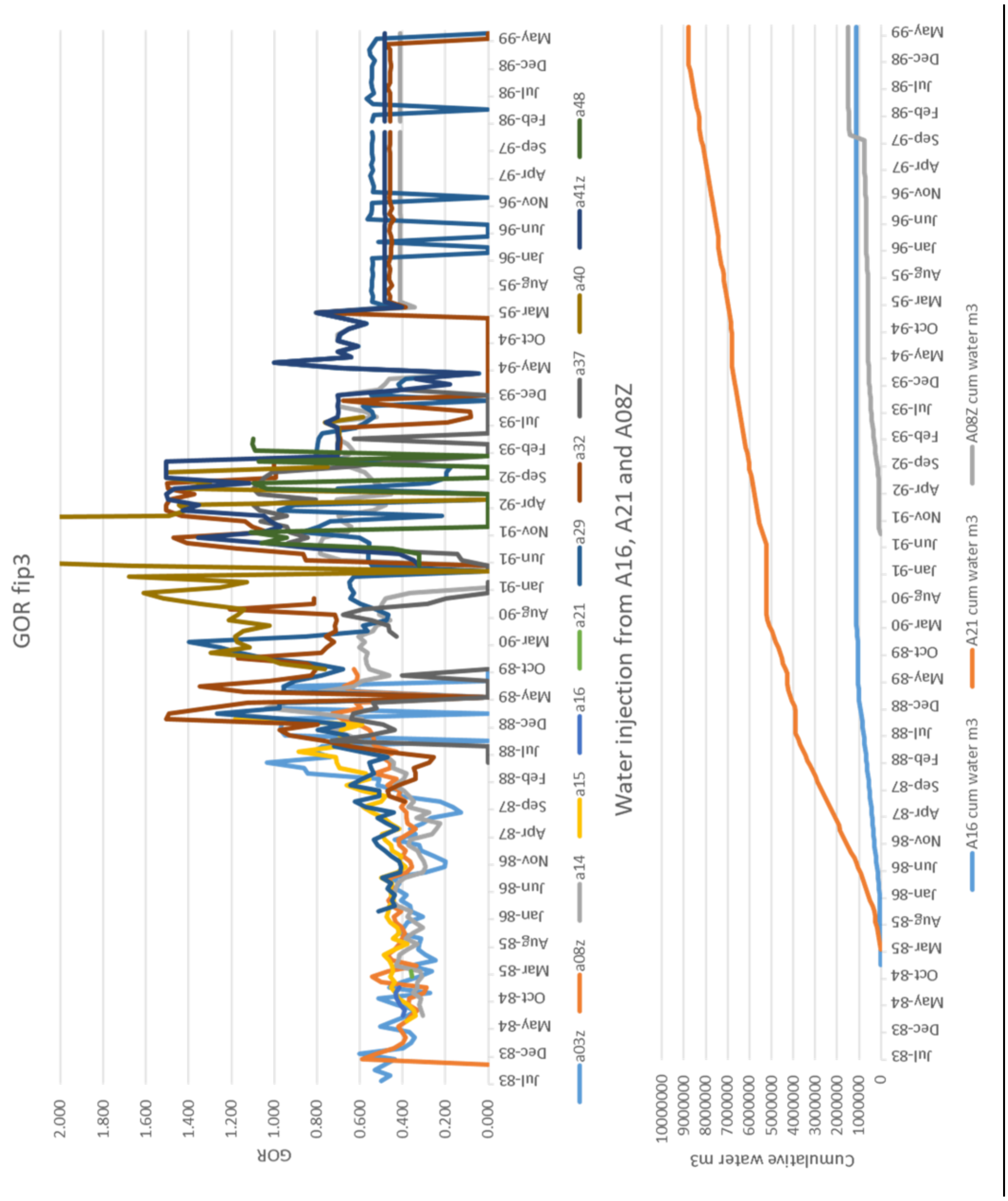


Figure 47- GOR and Water Injection in fip3

Gas oil ratio (GOR) values (Figure 47) should be analysed with caution because it is very sensitive to oil rate. The data for March 1995 onwards is assumed as a data error due to data suddenly flattening.

Between July 1983 and February 1988 GOR remained steady. It increased in all wells producing at the time from February 1988 to January 1991 as pressure dropped, after which it shows a downward trend as gas got depleted. GOR starts low in the early wells A03Z, A08Z, A14, A15, A16, A21 and A29. A40 stands out from others as having a high GOR >4.5, which rapidly decreased. A08Z and A14 had the lowest GOR and A29 had large variations in GOR.

3.3.8 Well by well analysis

Wells have been compared to nearby injectors with the potential to provide pressure support.

3.2.8.1 A03Z

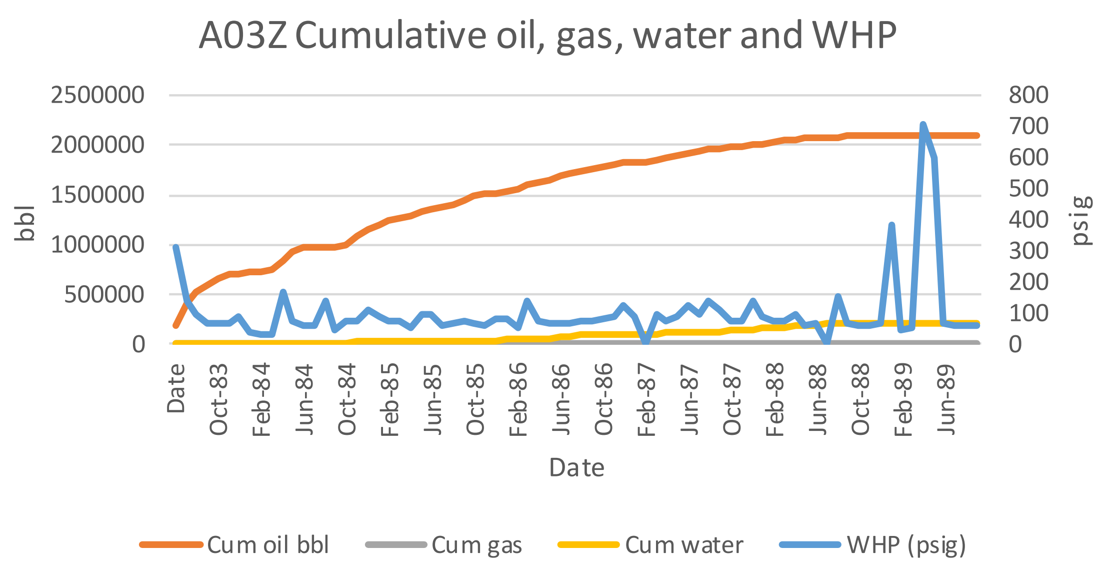


Figure 48- A03Z Cumulative Oil, Gas, Water and WHP

Cumulative water of A03Z was low (Figure 48).

3.2.8.2 A08Z

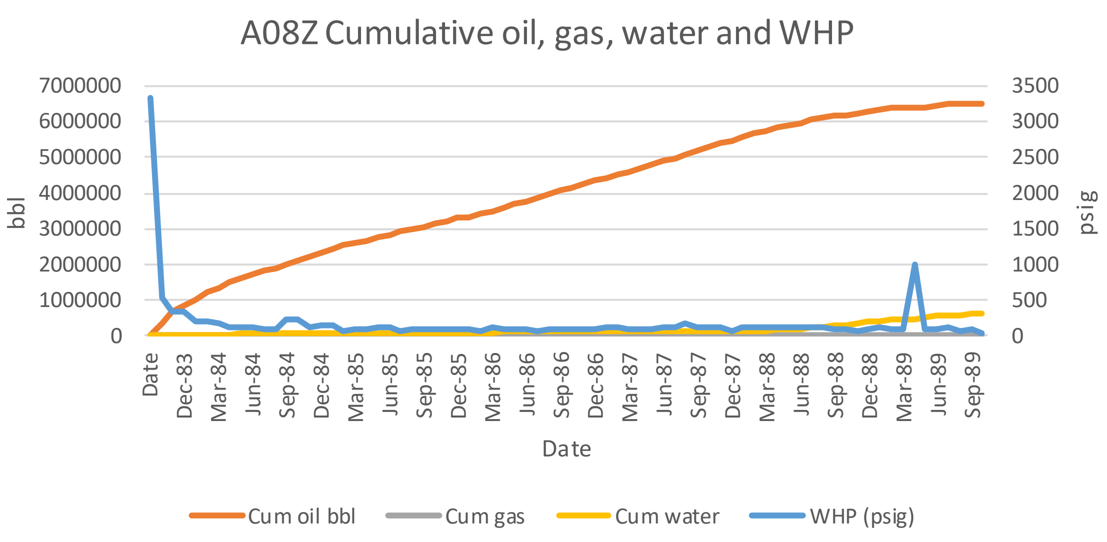


Figure 49- A08Z Cumulative Oil, Gas, Water and WHP

There was little cumulative water production, it produced at a very slow rate, which slightly increased in July 1988. Cumulative oil increased steadily and was still steadily increasing with no plateau when production ceased (Figure 49).

3.2.8.3 A14

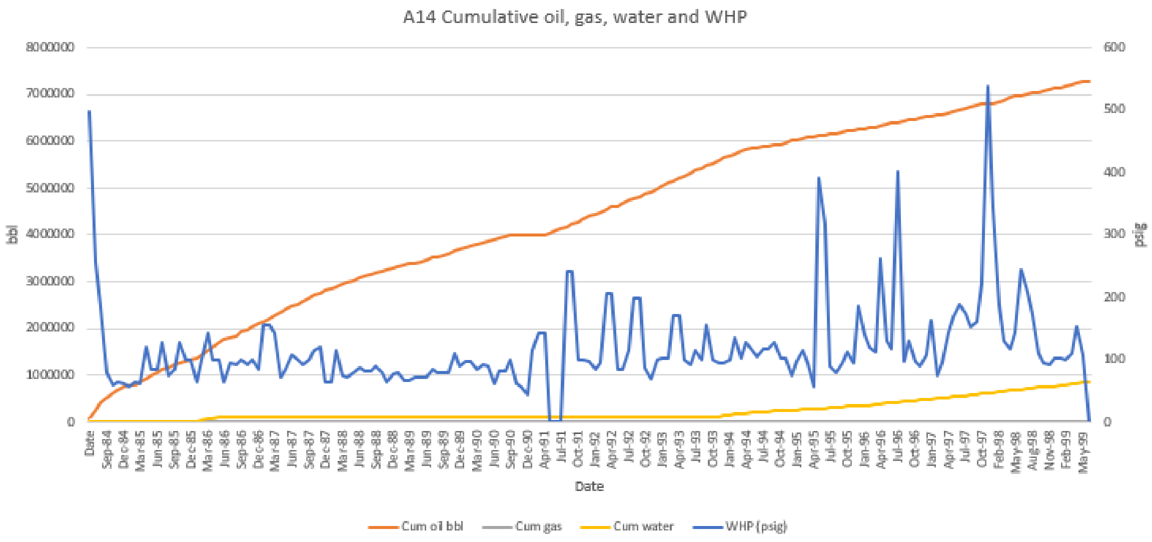


Figure 50- A14 Cumulative Oil, Gas, Water and WHP

A14 was the second best oil production well with a total of 7.27 mmBBLs of oil produced consistently over 13 years and 7 months (Figure 50). Oil production did not plateau after a few months like most other wells in fip3. A14 had a slow steady build up of water production (Figure 50).

3.2.8.4 A15

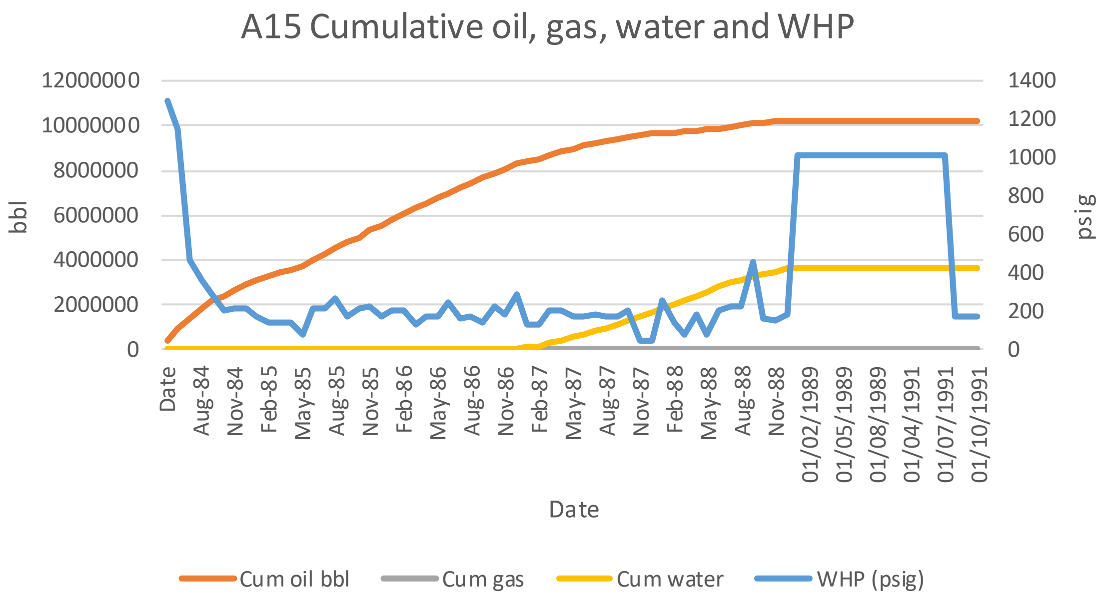


Figure 51- A15 Cumulative Oil, Gas, Water and WHP

A15 had the highest cumulative oil (Figure 43) and water (Figure 44) production and the highest initial oil rate of 16,765 bopd (Figure 45).

Water production began in August 1986 (Figure 51). A15 was a good oil producer and no more oil or water was produced after December 1988.

3.2.8.5 A16

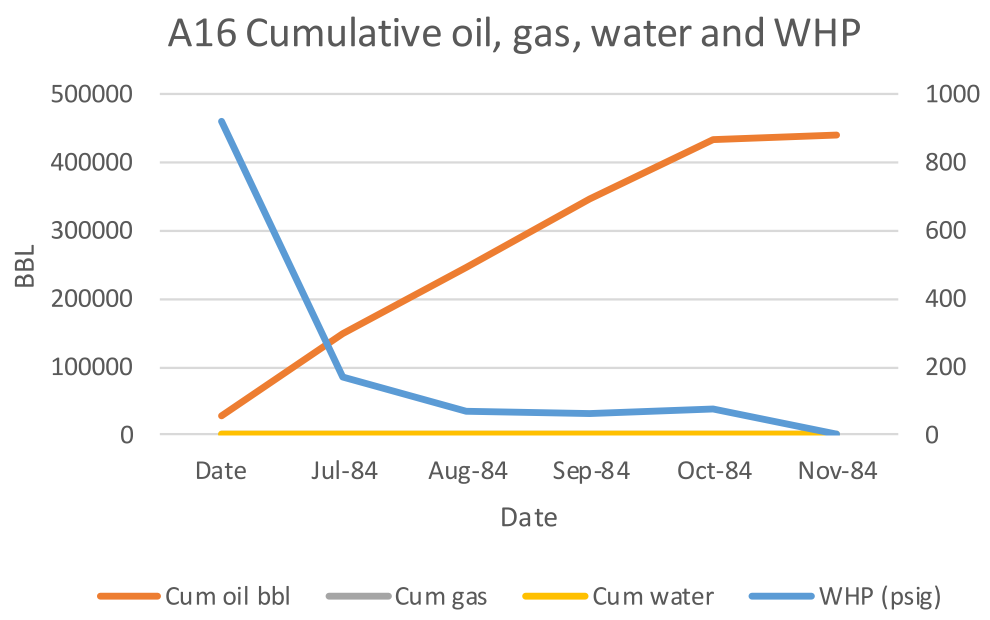


Figure 52- A16 Cumulative Oil, Gas, Water and WHP

A16 was converted to a water injector, and there were no other injectors operating at its time of production. It only operated over a period of 6 months. The starting oil rate (4872 bopd) was slightly lower than the other early wells (Figure 45). Oil rate dropped steadily (Figure 45), and oil production had plateaued by November 1984 (Figure 52).

3.2.8.6 A21

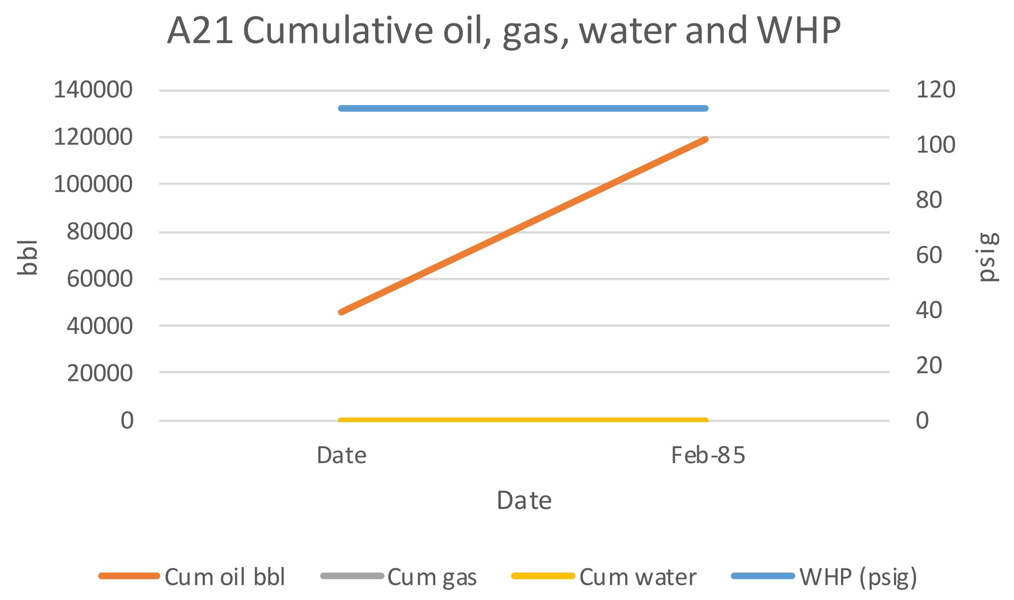


Figure 53- A21 Cumulative Oil, Gas, Water and WHP

A21 only produced for one month before it was converted to a water injector. It is difficult to observe trends over such a short time period.

Initial oil rate was more similar to that of the later wells (3669 bopd) (Figure 45). Oil rate increased over the month of production, WHP remained steady and no water was produced (Figure 53).

3.2.8.7 A29

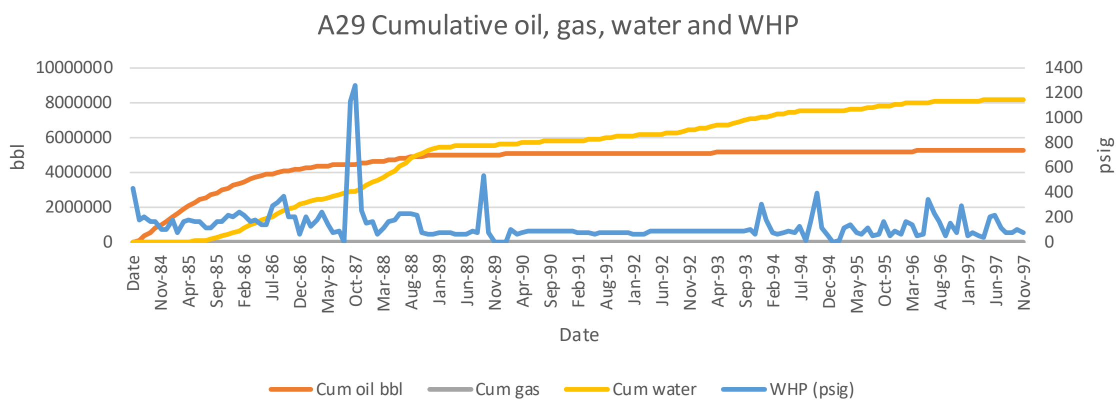


Figure 54- A29 Cumulative Oil, Gas, Water and WHP

A29 had the 4th highest cumulative oil (Figure 43) and high water production (Figure 44). Initial oil rate was relatively high, typical of a well at this time (Figure 45).

3.2.8.8 A32

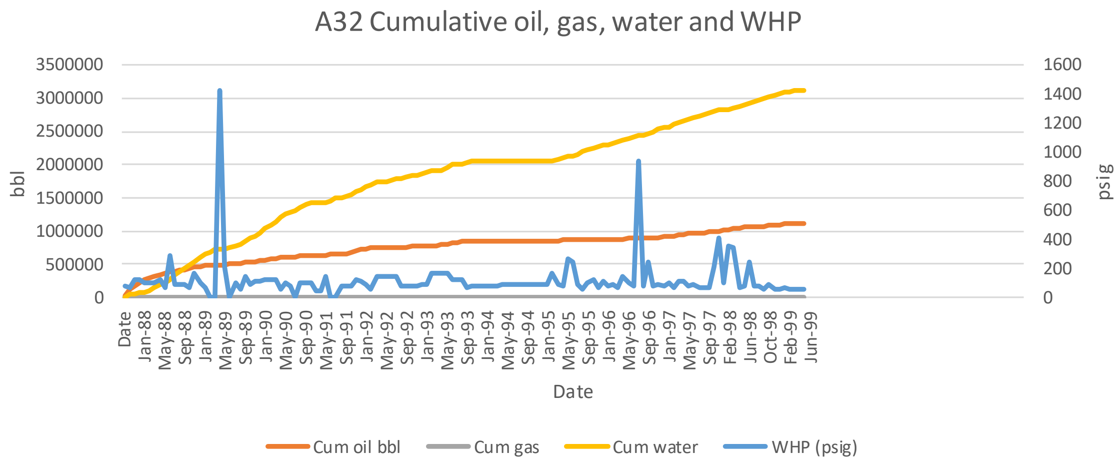


Figure 55- A32 Cumulative Oil, Gas, Water and WHP

A32 was a slow steady producer of oil and water production and did not plateau (Figure 55). Oil rate started relatively low (3090 bopd), typical of the later wells at this time (Figure 45). It dropped quickly and generally was low and steady throughout production.

3.2.8.9 A37

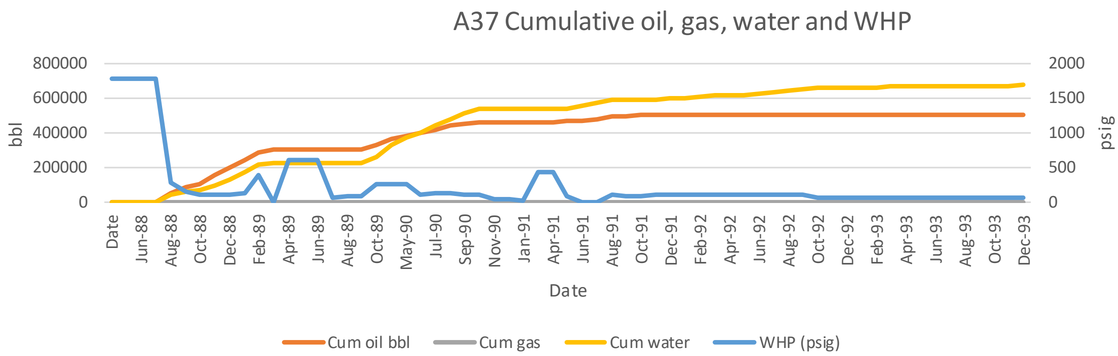


Figure 56- A37 Cumulative Oil, Gas, Water and WHP

Most of the cumulative oil had been produced by August 1991, however production continued until December 1993 (Figure 56).

3.2.8.10 A40

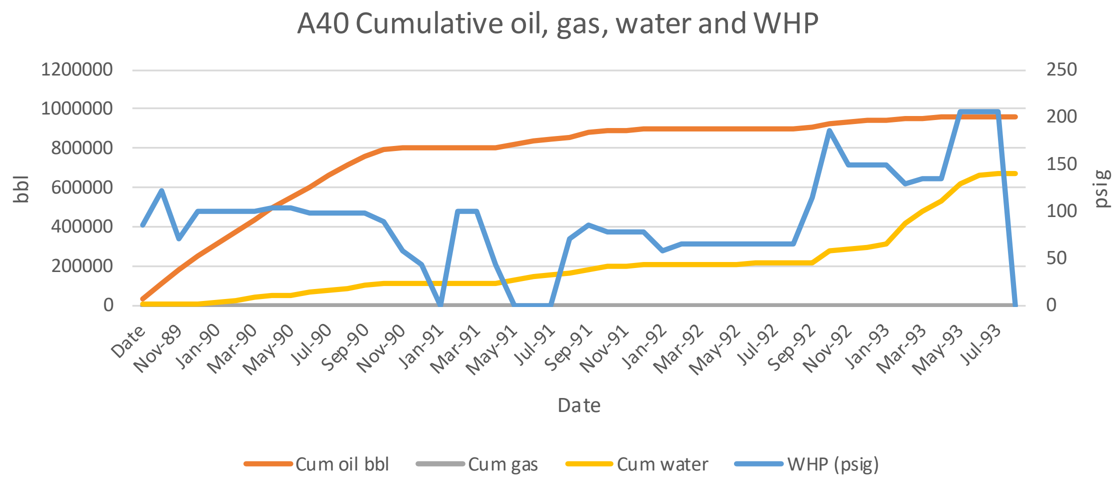


Figure 57- A40 Cumulative Oil, Gas, Water and WHP

The initial oil rate (2760 bopd) is typical of the later wells (Figure 45). A40 had the highest GOR in fip3 (>4.5) (Figure 47). Water production was slow and steady, with the rate increasing in September 1992. WHP was highly variable (Figure 57).

3.2.8.11 A41Z

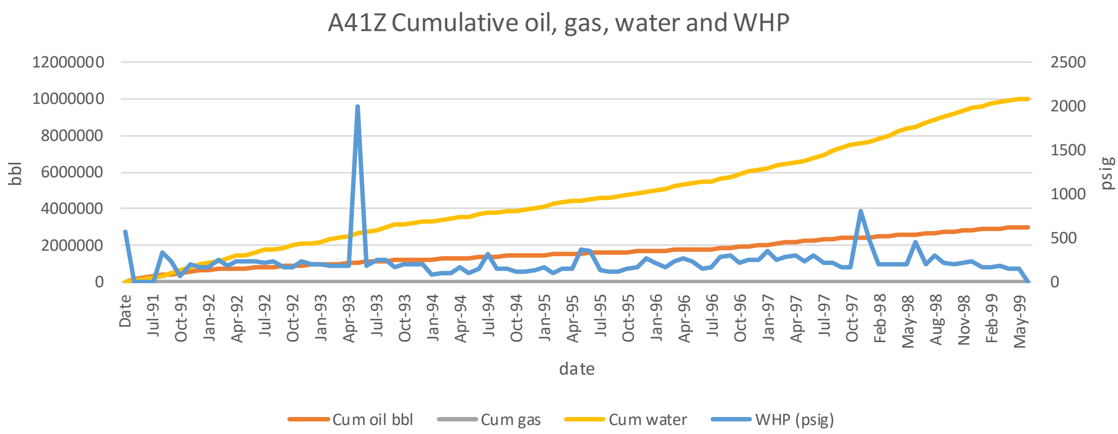


Figure 58- A41Z Cumulative Oil, Gas, Water and WHP

A41Z had a very high cumulative oil (Figure 43) and initial oil rate (10518 bopd) (Figure 45) for a late well.

3.2.8.12 A48

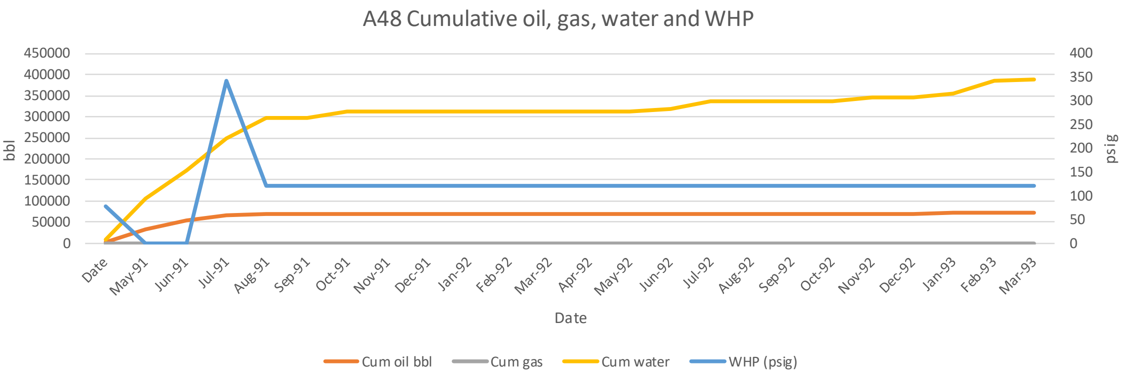


Figure 59- A48 Cumulative Oil, Gas, Water and WHP

A48 had low cumulative oil (Figure 43) and water production (Figure 44). There was minimal oil production after the first month of production (Figure 59), but the well remained on production for 22 months.

WOR was reached in August 1991, after 4 months of production. Initial oil rate was low (Figure 45), consistent with the oil rates of later wells. It rapidly dropped (Figure 113), fluctuated but remained low (<2 mmBBL) with 3 small increases in September 1991, June 1992 and November 1992. It does not appear to be affected by water injection.

WHP had an initial spike in August 1991 (Figure 114), but immediately decreased as GOR increased (Figure 112), after which WHP was steady.

A48 had the highest starting WOR of 3.1. 20 WOR was reached in January 1993 and was steady after. In July 1991 GOR and WOR increased as WHP and oil rate rapidly decreased.

4 Well Performance

This chapter analyses the dynamic behaviour of individual wells and the production performance of fip3 as a whole.

Pressure support has been studied, depleted areas identified and where there may be unswept oil indicated. Production performance has been analysed both spatially and temporally with interactions between wells and injectors investigated.

The effect of facies on reservoir quality has been assessed, the best reservoir units identified and a reservoir model of the Etive and Ness Formation's sandbodies has been produced (Figures 115 and 116). The plumbing system, connectivity, sandbody architecture and compartmentalisation have been described across fip3.

4.1 Individual Well Performance

4.1.1 A03Z

Cumulative oil (2.11mmBBLs) was lower than other early wells A08Z, A14 and A15 (Figure 43), this may have been restricted by the low net sandstone thickness (259ft).

Reservoir quality is high, the Etive, LNE-G and UNA-C have particularly high porosity.

PLT data show that production came from the Etive Formation, LNE-F, UNA-C, UNG and the Tarbert Formation. Most of production came from the Etive Formation and UNA, they have high permeabilities and porosities and lack of compartmentalisation by shale and cement. The upper UN also produced a minimal amount of oil from thin, poorly connected crevasse splay sandbodies. There still may be oil remaining in these unperforated lower permeability sandbodies.

The Broom Formation, Rannoch Formation, and LNA-D did not produce. The Broom, and the majority of the Rannoch are below the OWC. Thin cemented intervals are present in the Rannoch, LNF and UND, they reduce vertical permeability and these layers do not produce well.

The initial oil rate was the 3rd highest in fip3 (10,883 bopd) (Figure 45). Rapid increases and decreases in oil rate (Figure 60) can be attributed to 3 single channels being drained. In May 1984 the first and largest spike (3922 bopd) in oil rate occurred as UNA-C began production together. Their production decreased with oil rate until September 1986 where UNB and UNC were no longer producing. It is likely that these high permeability layers had been drained of oil. Another spike in oil rate occurred between September 1984- May 1985 (2962 bopd) as the Etive Formation was reperforated and increased production in December 1984. By September 1986 the Etive Formation was no longer producing despite 3 reperforations (shown in PLT data, Appendix). Water injection did not appear to have much of an effect on oil rate (Figure 60). It is difficult to attribute a cause for the final major increase in oil rate, as there is a lack of PLT data at this time and production overall was low. Production from the Tarbert Formation increased in September 1986 (PLT data, appendix) so the Tarbert Formation may be contributing to the increase in oil rate.

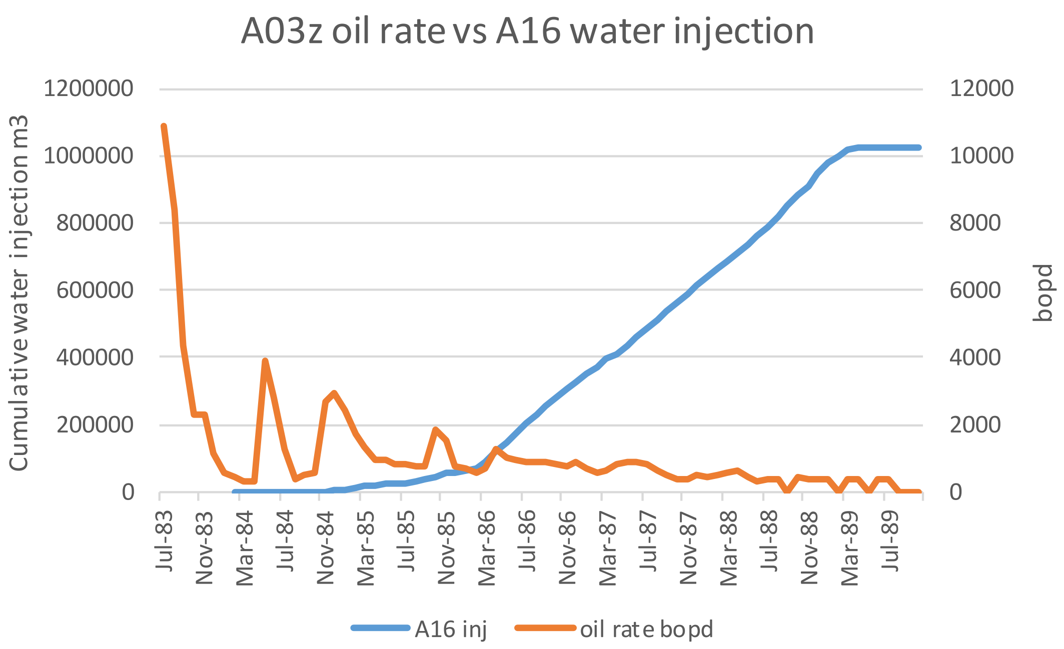


Figure 60- A03Z Oil Rate vs A16 Water Injection

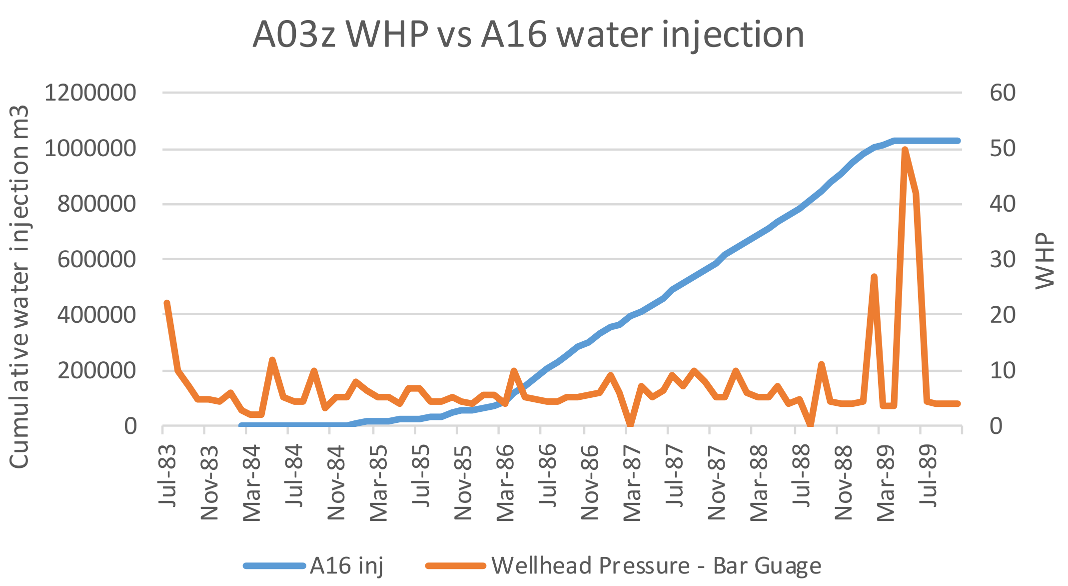


Figure 61- A03Z WHP vs A16 Water Injection

Formation water support is interpreted to have been coming in between July 1983 and July 1986, indicated by the gradual increase of WOR (Figure 62). A16 water breakthrough (through

UNA and the Tarbert) is interpreted in July 1986 by a sudden increase in WOR simultaneous to a rapid decrease in GOR (Figure 62). Oil rate and WHP were not affected (Figure 61) and after breakthrough oil rate remained low and continued to decrease. Water injection did not have much of an effect on oil rate because pressures were already high and the majority of oil had been swept.

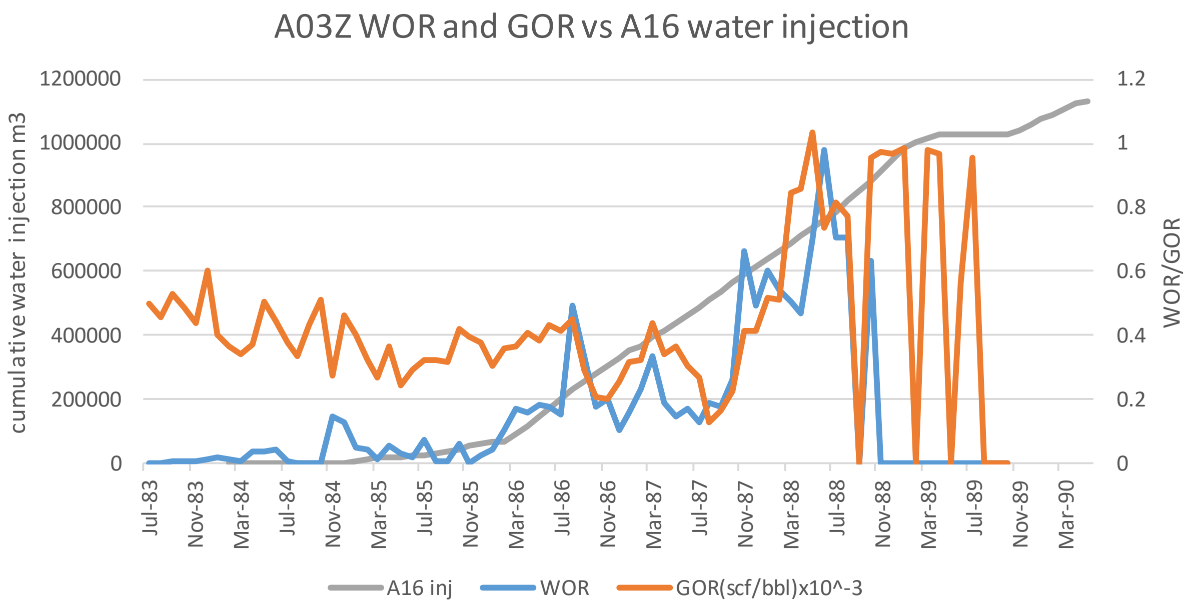


Figure 62- A03Z WOR and GOR vs A16 Water Injection

A03Z performed well, this is partly attributed to it having been drilled and completed early in field history, typically resulting in higher pressures, less scaling and oil not previously having been swept.

Over production WOR remained low (<1) indicating there is still oil remaining, however this would have been swept from the permeable units by water injection from A16 at a later date. Oil may remain in unswept, lower permeability horizons such as LNA-D.

4.1.2 A08Z

A08Z was the 3rd best oil producer, with 6.54 mmBBL of oil produced and a high initial WHP and oil rate.

The Brent Group in the area is thick but is highly compartmentalised by thin cemented intervals and shale beds, giving poor vertical permeability and reducing oil production from the Ness Formation. There is no RFT data to observe depletion behaviour and compartmentalisation in A08Z.

All units excluding the Broom Formation were oil saturated. Production came from the Etive Formation, LNA-D, UNE-F and the Tarbert Formation. LNA-D and UNE-UNF produced together despite thin shales compartmentalising. The Etive and Tarbert Formations are thick and of excellent porosity and permeability. UND-G produced a very small amount, and LNG did not produce, but is heavily cemented reducing permeability and porosity. The upper UN did not produce but is highly cemented with no hydrocarbon filled sandstones indicated on the CPI log. Fluvial channels in UNC-G are very thin and compartmentalised and of fine sandstone, silty in part and did not produce particularly well.

A08Z had the highest initial well head pressure (WHP) and the 2nd highest initial oil rate (13949 bopd) (Figure 45).

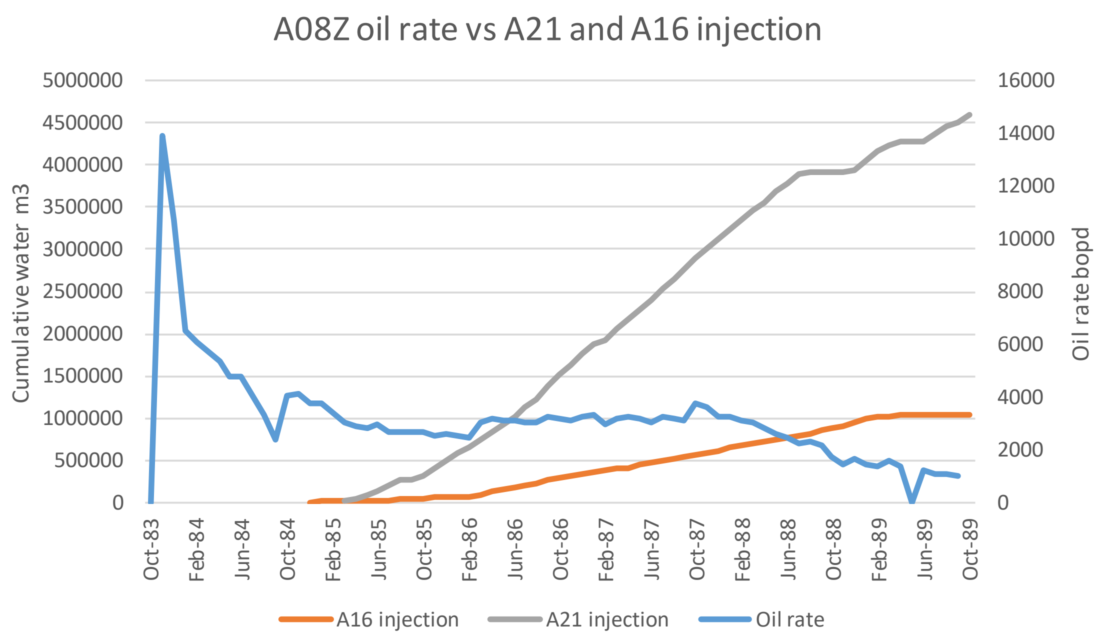


Figure 63- A08Z Oil Rate vs A21 and A16 Water Injection

Oil rate rapidly dropped and the well did not appear pressure supported until September 1984 where there was an increase in pressure (Figure 63). This was before injectors A16 and A21 were turned on, therefore this oil rate increase is not considered to be caused by water injection. PLT data show that between November 1983 and October 1984 the Etive Formation and UNE-G began producing, so the increase in oil rate may be attributed to these layers beginning oil production. The increase in oil rate may also be due to natural pressure support, as A08Z is located close to the pool of water in the structural low of fip3 (Figure 37).

After September 1984 the oil rate was steady (Figure 63), and the well appeared pressure supported as A16 and A21 began injection. The oil rate of A08Z decreased as the adjacent well A32 began production in November 1987 (Figure 64). This indicates that A32 had been drilled too close to A08Z and “stolen” its production. They both experienced another sharp drop in oil rate in May 1989.

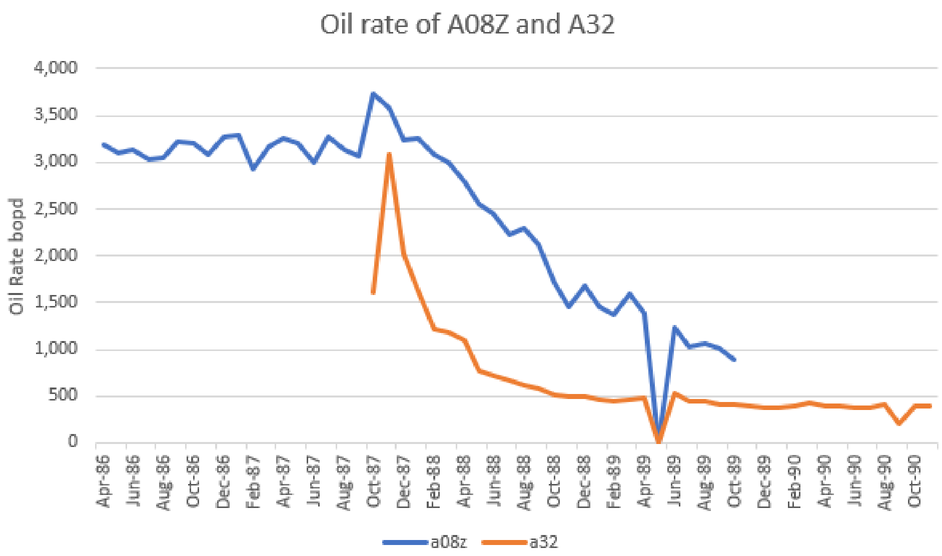


Figure 64- Oil rates of A08Z and A32

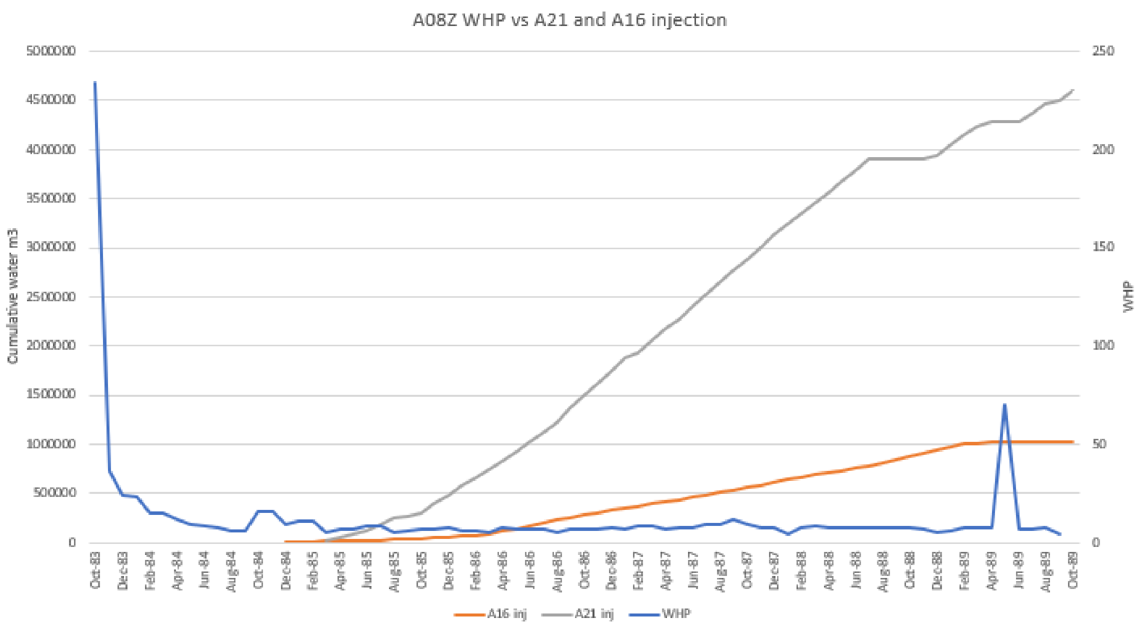


Figure 65- A08Z WHP vs A21 and A16 Water Injection

WOR was steady and low <0.1 (Figure 65) as the oil rate rapidly dropped. Before injectors were turned on there was a spike in WOR in August to October 1984, where GOR decreased (Figure 65) as WHP (Figure 65) and oil rate increased (Figure 63).

Water breakthrough from A21 is interpreted to be in January 1988, with a sudden increase in WOR parallel to the incline in A21 water injection (Figure 65). Oil rate was not affected by this. There is no clear evidence for water breakthrough from A16, but the oil rate appeared pressure supported before the A21 water breakthrough. A08Z had the lowest GOR in fip3 (Figure 47), which remained steady, slightly increasing as WOR increased after January 1988, indicating only a slight pressure drop as gas exsolved with pressure increase.

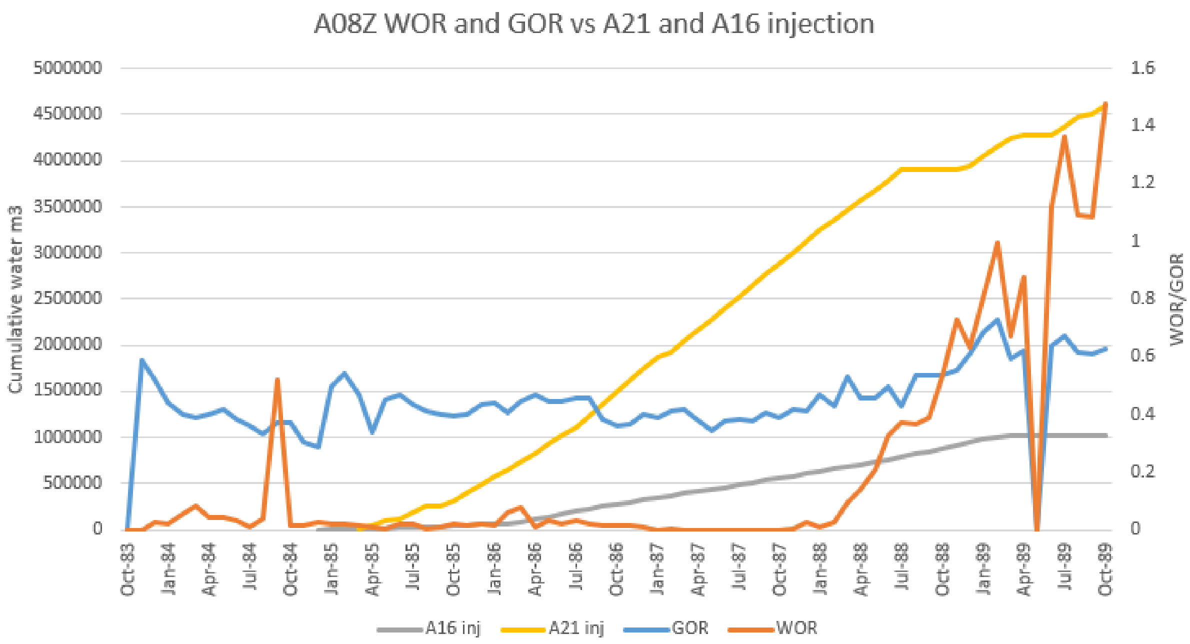


Figure 66- A08Z WOR and GOR vs A21 and A16 Water Injection

WOR remained <1.5, indicating that there was still oil left when the “fish in the hole” event occurred, however since being converted to a water injector oil would have been expelled to nearby wells. Surrounding wells A40, A32 and A37 all reached 20 WOR, indicating that the area of fip3 is swept. However, there may still be oil remaining in the isolated, unswept, lower permeability sandbodies.

Its good performance is attributed to a high net sandstone thickness of 477.65ft with non-compartmentalised rock, and being early well, meaning that pressures were still high and oil had not yet been swept.

4.1.3 A14

A14 was the 2nd best oil producer with a total of 7.27mmBBLs of oil produced consistently over a long period of time. It is a deep well to the south of fip3, and not close to any other wells to "steal" oil production.

A14 has a very high net sandstone thickness of 606ft. The geology is high quality, particularly the Etive Formation, with thick sandstones, thin shales and a lack of cementation making it possible for sandstones to be in pressure communication. A14's initial oil rate (5780 bopd) was lower than other early wells A03Z, A08Z, A15 and A29 (Figure 45), indicating pressures were lower to the south of fip3.

RFT data (Appendix) show that the Upper Ness Member was in pressure communication. The Upper Ness was depleted and the Etive Formation and Lower Ness Member were in pressure communication.

PLT data (Appendix) from 1984 show that production came entirely from the LNG and UNA-G. UNA-C and UNE-G flowed together. The Ness Formation was oil saturated with high permeability and porosity. In UNA-C fluvial channel type B are stacked with no shale in-between allowing sandbodies to flow together. Despite being thick and excellent quality, the Etive Formation (along with the Broom and Rannoch Formations) is below the OWC, which is higher to the south of fip3 (ODT 11733ft) and water saturated. The upper UN did not produce and is shaley with low permeability however there are thin crevasse splay sandbodies which may be oil bearing. LNA-E and the Tarbert Formation both have good permeability and are relatively oil saturated but showed no production. There is no PLT data past 1984 to see if these layers have produced.

Initial oil rate was high (13949 bopd) and rapidly decreased (Figure 67). Oil and water production rate increased in June 1991 as A08Z water injection began. GOR increased as oil rate dropped due to a reduction in pressure (Figure 69). After 6 mmBBL GOR was very flat and appears to be a data error. Oil rate increased in February 1986. There was another increase in oil rate and GOR in October 1993, with parallel increases in A32 and A41Z despite not being geographically close. Oil rate steadily decreased after December 1983, at this time both A21 and A08Z were injecting at a high but steady rate. PLT data are only available for July 1984, so it is difficult to attribute increases in oil rate to draining of new channels.

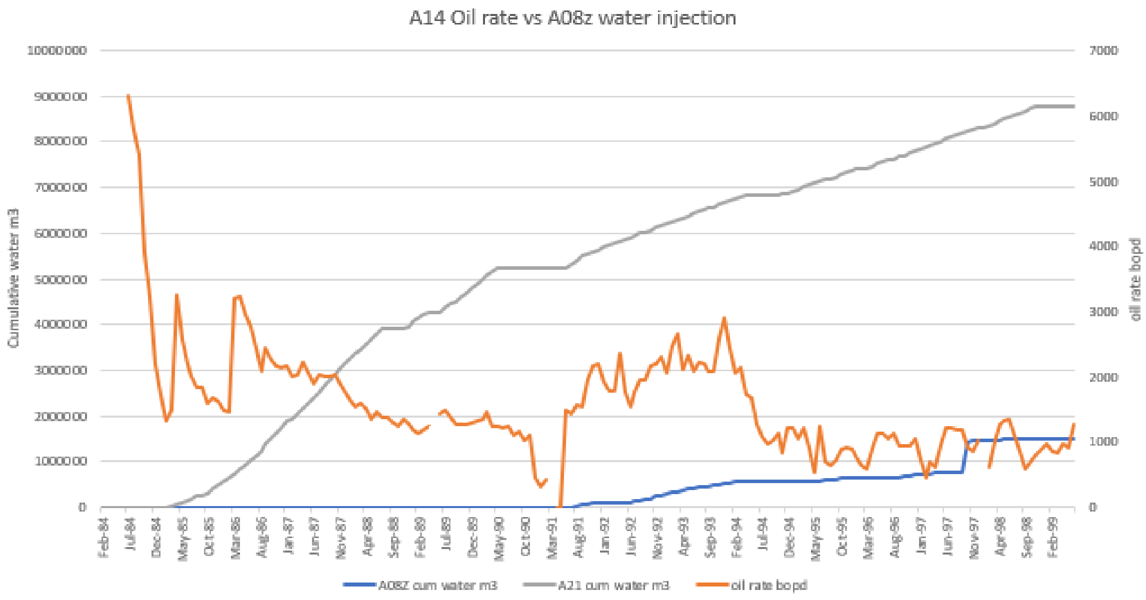


Figure 67- A14 Oil Rate vs A08Z and A21 Water Injection

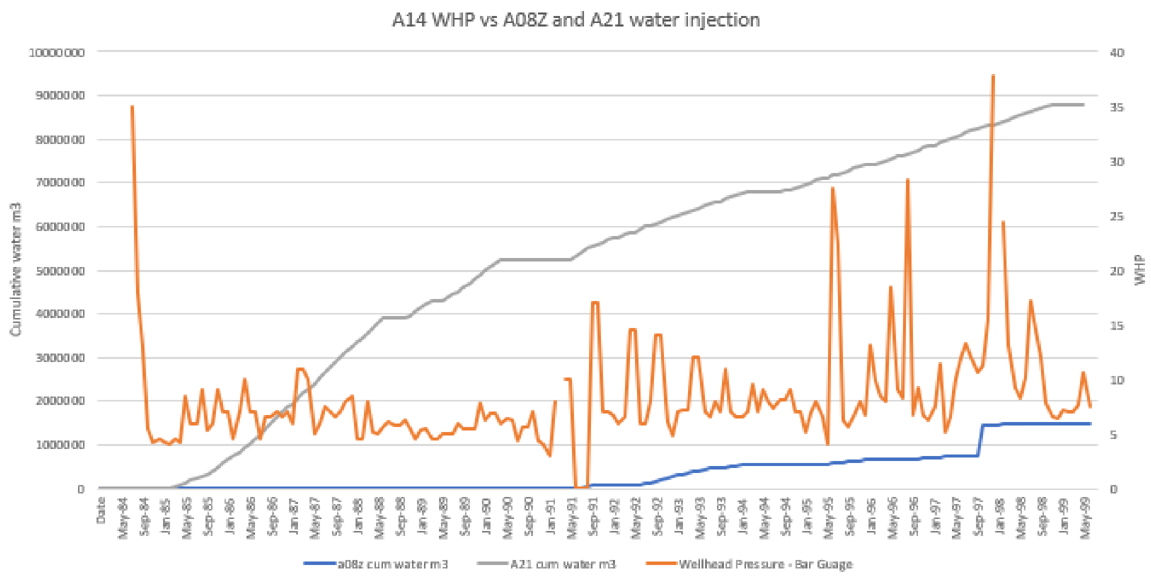


Figure 68- A14 WHP vs A08Z and A21 Water Injection

A14 displays a different WOR trend to other fip3 wells (Figure 46), it remained very low <1 despite a long time on production, indicating consistent pressure support, evidenced in A14's steady production of oil over a long period of time (Figure 43). The oil rate decreased slowly, indicating the well was pressure supported between October 1984 and January 1989. The south of fip3 has a higher OWC (11733ft) and is located close the pool of water (Figure 37), meaning that formation water support was likely present. Significant WOR increases occurred in

February 1984, June 1986 and January 1989, the latter is interpreted as the A21 water breakthrough event as this timing fits with the waterfront mapping (Figure 100). A08Z water breakthrough is indicated in January 1994 by a huge WOR increase and GOR decrease. After this WOR was much higher and had a serrated appearance. GOR was relatively low and increased as oil rate dropped (Figure 69 and 67 respectively).

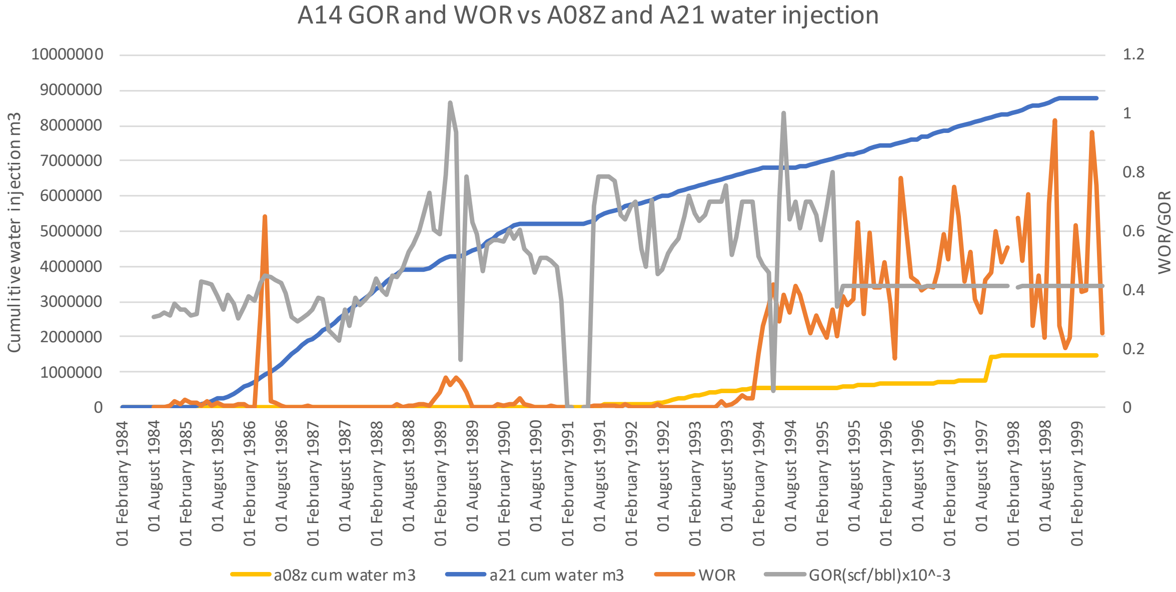


Figure 69- A14 WOR and GOR vs A08Z and A21 Water Injection

4.1.4 A15

A15 produced the most oil and water in fip3 and had the second highest net sandstone thickness (479ft). RFT data indicate that the rock is not compartmentalised, and sandbodies were in pressure communication. This is supported by the CPI log showing very little cementation and shale layers are sparse and very thin, giving excellent vertical permeability. Rock quality is good here with thick, oil saturated sandbodies of high porosity and permeability.

The best producing units shown by PLT data (Appendix) were the highest permeability layers, the Etive Formation and LNG. The Broom Formation, LNE-F, UNA, UNC, UNE-G and the Tarbert Formation all produced. LNA-D and UNE-G have lower permeabilities and produced only a little, there may be unswept oil here. The Broom Formation has very good rock quality and was oil saturated due to the low OWC (11788ft). The only other well in which the Broom Formation was producing was A16 this was controlled by burial depth and the OWC. The Rannoch Formation has poor permeability, two thin sandbodies had been perforated but did not produce.

A15 had the highest initial oil rate of 16765 bopd. Oil rate (Figure 70) and WHP (Figure 71) rapidly dropped until May 1985 where oil rate increased, this could be a result of natural pressure support or a new sandbody draining. Oil rate increased again in November 1985, then dropped until July 1988, where there was another small increase, WHP increased and WOR rapidly decreased (Figure 72). PLT data (Appendix) showed little change from January to August 1988 so it is not indicated to having been a new channel draining.

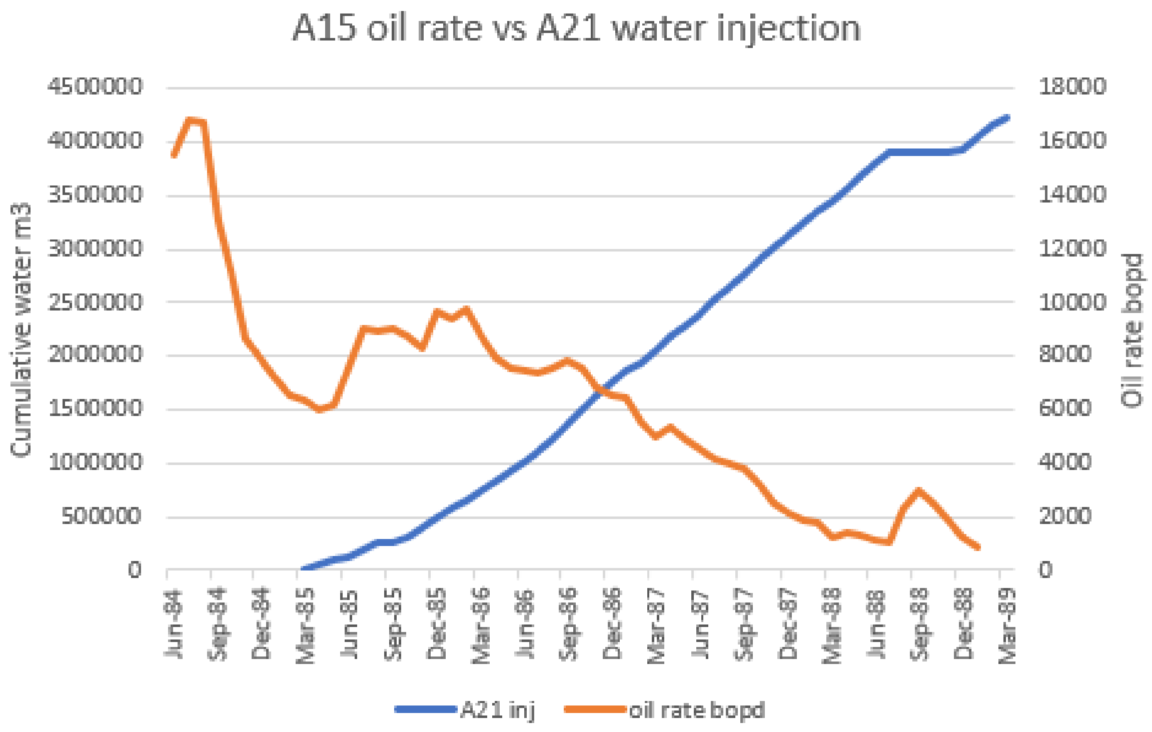


Figure 70- A15 Oil rate vs A21 Water Injection

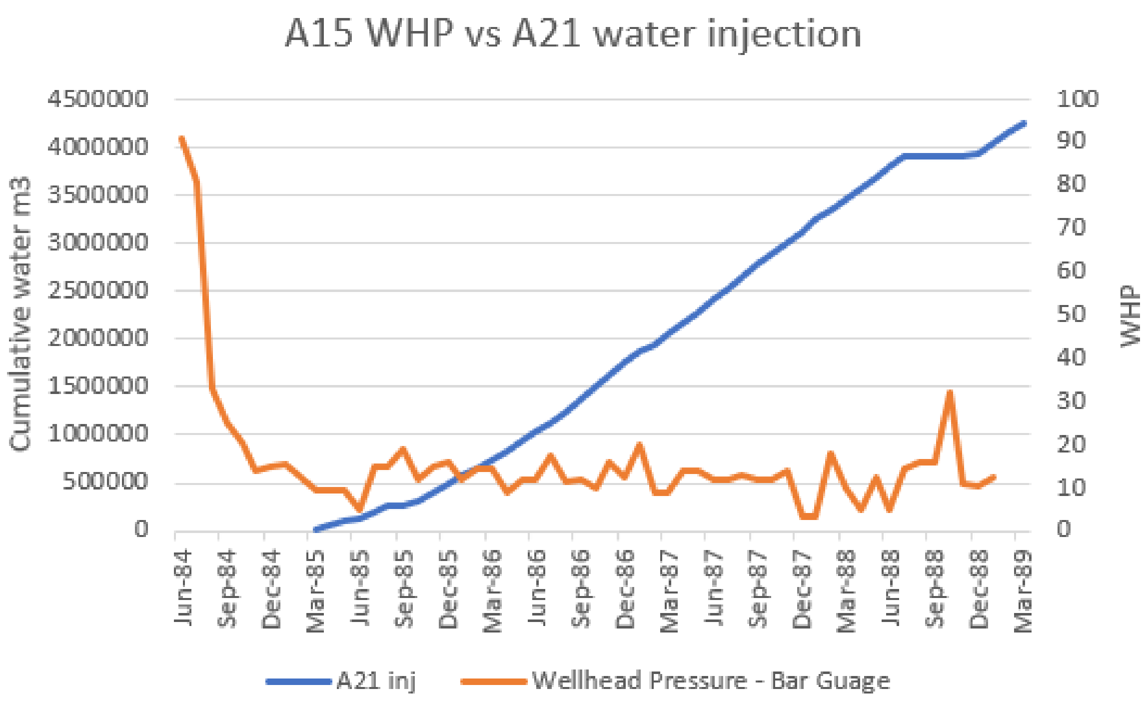


Figure 71- A15 WHP vs A21 Water Injection

Water breakthrough from A21 is interpreted to reach A15 in January 1987 as WOR had a huge increase from 0.9 to 6.5 (Figure 72). There is no PLT data from this time, so it is unclear which layers injection water entered. WOR had a small drop in April 1988 and a large drop in July 1988, which increased again in September 1988. GOR remained relatively constant and low, slightly increasing from 0.5 to 1 over production**.**

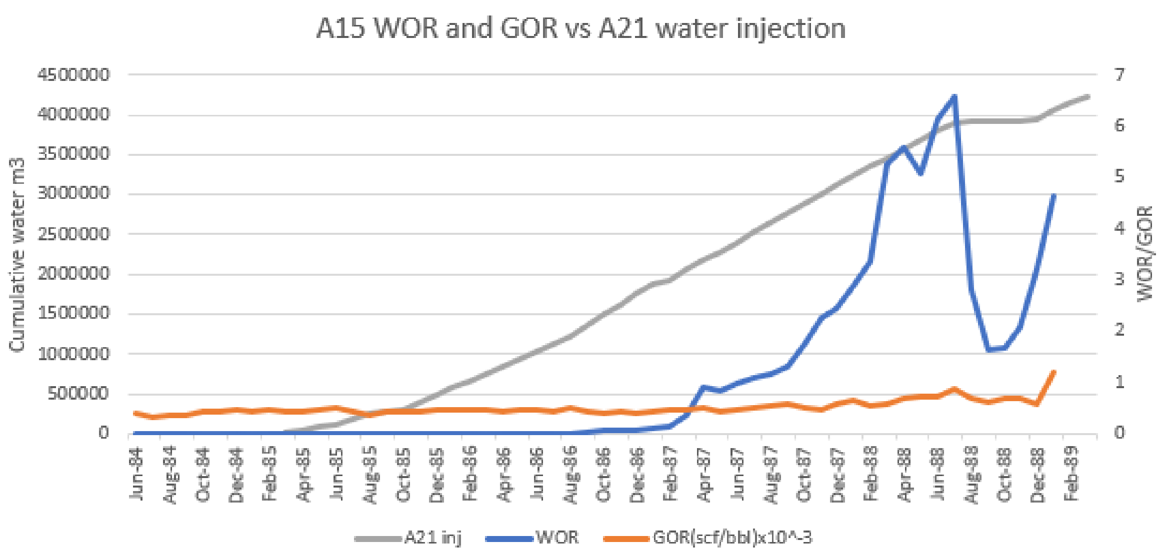


Figure 72- A15 WOR and GOR vs A21 Water Injection

Shut in was due to operational issues, by this time oil rate was decreasing. WOR reached a maximum of 6.5 indicating 95% water cut has not been reached and there may still be unswept oil. However, A15 is on A21's water injection path (Figure 100) and A48 and A29 nearby both reached 95% water cut so oil would have been swept of the high permeability sandbodies. Oil may remain in the lower permeability units LNA-D and UNE-G.

A15's good performance is attributed to excellent rock quality, lack of compartmentalisation, high net sandstone thickness, being an early well and receiving consistent pressure support from A21.

4.1.5 A16

A16 had a low cumulative oil (0.44 mmBBLs) compared with the other early wells (Figure 43). This can be partly attributed to the fact that it was converted to a water injector in December 1984 despite producing 4000 BOPD in September 1984.

Rock quality and net sandstone thickness were low, there is a lack of good porosity hydrocarbon filled sandstones shown by the CPI log (Appendix). The most permeable layers (LNE, LNG, UNA, UNE and UNG) all produced. The Etive Formation had good quality geology but only produced a little.

RFT data also show that the Upper Ness Member was depleted and highly compartmentalised by claystone, coal and cement. The pressure (6236-7000 psi) was higher than most other wells in fip3 indicating it was less depleted and oil had not previously been swept.

It is difficult to analyse A16 as it was only producing for a few months. Initial oil rate (4872 bopd) (Figure 45) was just a little lower than other early wells.

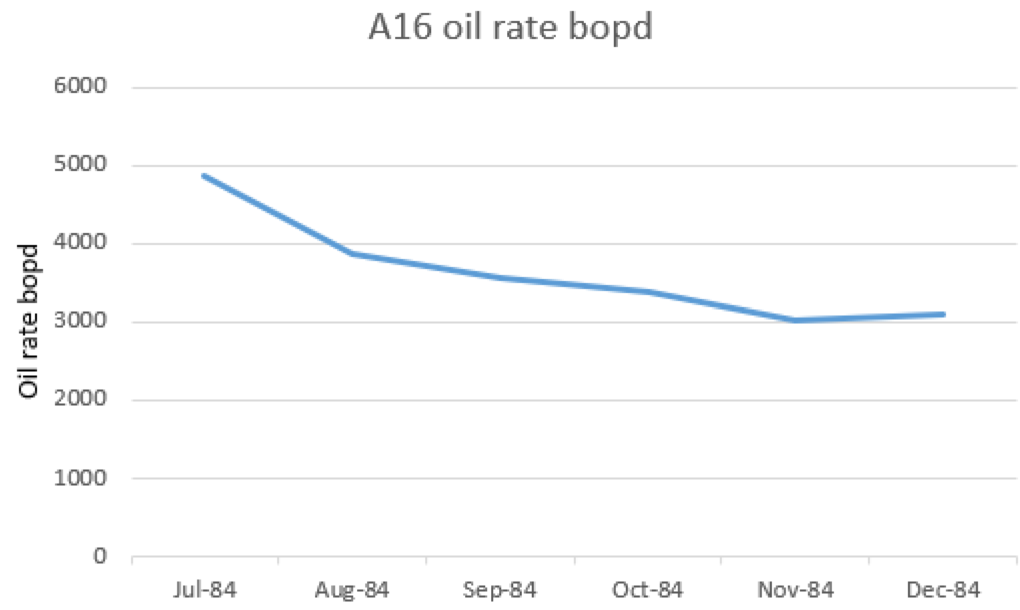


Figure 73- A16 Oil Rate

Oil rate dropped rapidly (Figure 73), was unstable and WOR (Figure 46) was very low at the start, giving no evidence of formation water providing pressure support. No water injectors were operating in fip3 whilst A16 was producing.

A16 had a low WOR and a typical starting GOR (Figure 47). WOR remained almost 0 (Figure 46) indicating there may have been unswept oil. A32 to the south reached 95% water cut but was on A21s water sweep path (Figure 100). It is unclear if A16 was on the sweep path. Any remaining oil in A16 would have been swept to nearby wells A03Z and A32 when it was converted to a water injector. There is no evidence for this observed in the oil rates of A03Z and A32 (Figures 60 and 80 respectively). However, as the rock, particularly the Upper Ness Member, is highly compartmentalised oil is likely to remain in isolated sandbodies.

4.1.6 A21

A21 was producing for one month (February to March 1985) before it was converted to a water injector. It produced 0.12 mmBBLs oil (Figure 53).

It had the 5th highest net sandstone thickness in fip3 and geology was of good quality, particularly the Upper Ness sandstones, which were thick and oil saturated with good porosity and permeability. RFT data show a large pressure range 2722-7212 psi, with depletion with decreasing depth. The Etive Formation, Lower Ness Member and UNG are compartmentalised.

PLT data show that the top Rannoch/Etive Formation, LNE-F, LNG, UNA-B, UNC, UNE, UNG and the Tarbert Formation were producing. LNE-F and UNA-B were flowing together. A21 is the only well which the interfluve area of the Etive Formation produced.

Initial oil rate was similar to that of the later wells (3669 bopd) (Figure 45). Oil rate increased over the month of production, WHP remained steady and no water was produced (Figure 53).

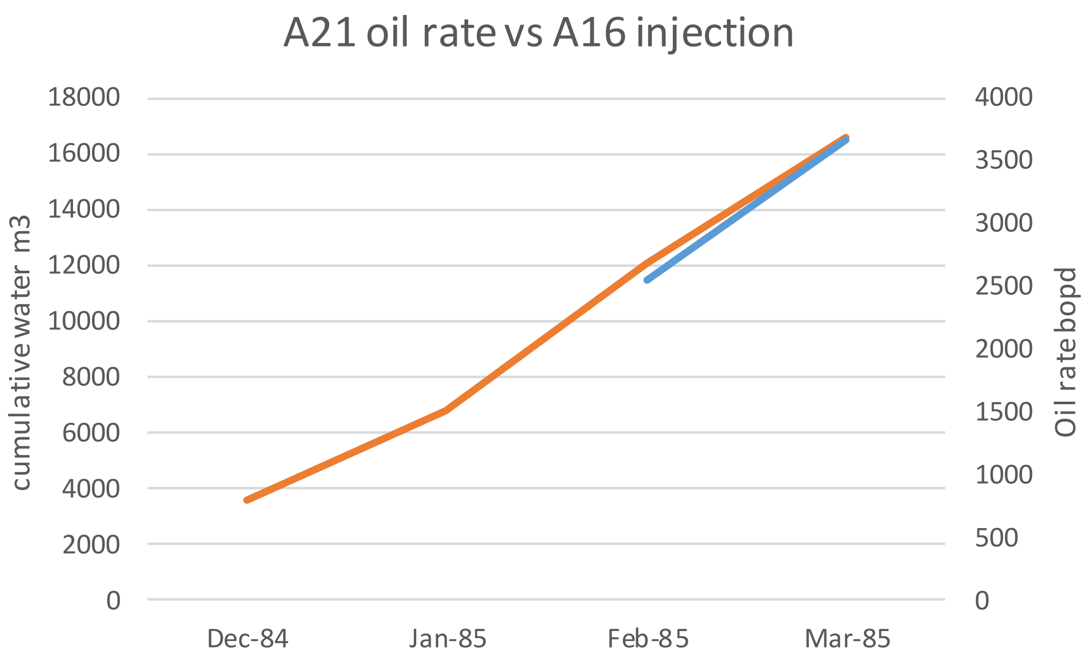


Figure 74- A21 Oil Rate vs A16 Water Injection

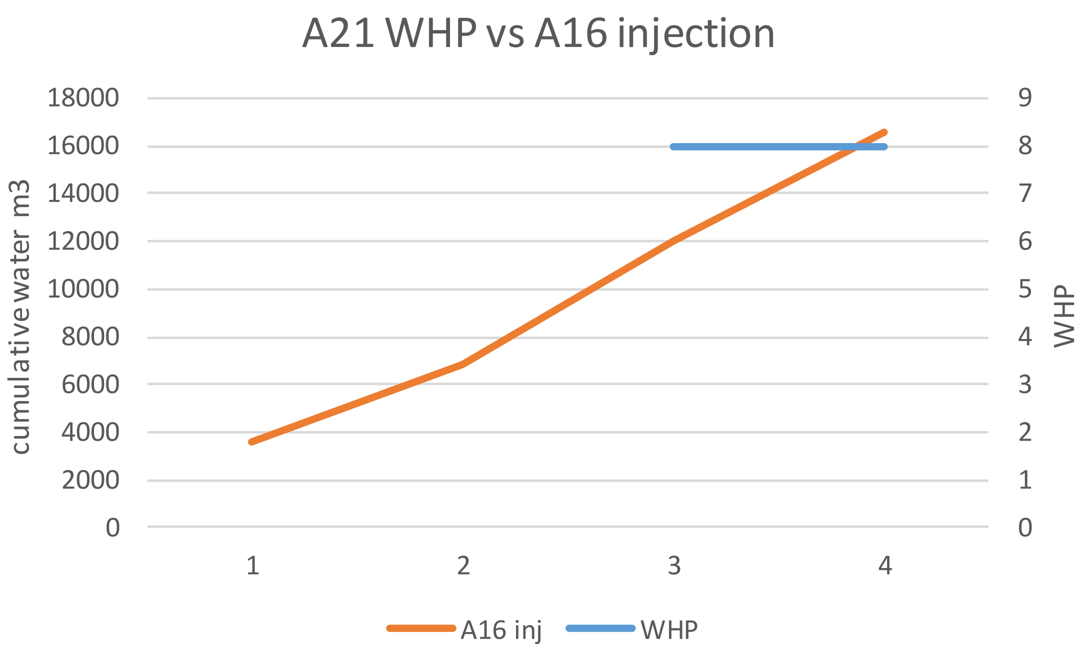


Figure 75- A21 WHP vs A16 Water Injection

It is unclear if A21 is received any pressure support due to the short time period of production. WOR was almost 0 (Figure 76), however unswept oil would be expelled to nearby wells when A21 was converted to a water injector in March 1985. Oil may remain in isolated sandbodies in the compartmentalised Lower Ness Member and Etive Formation.

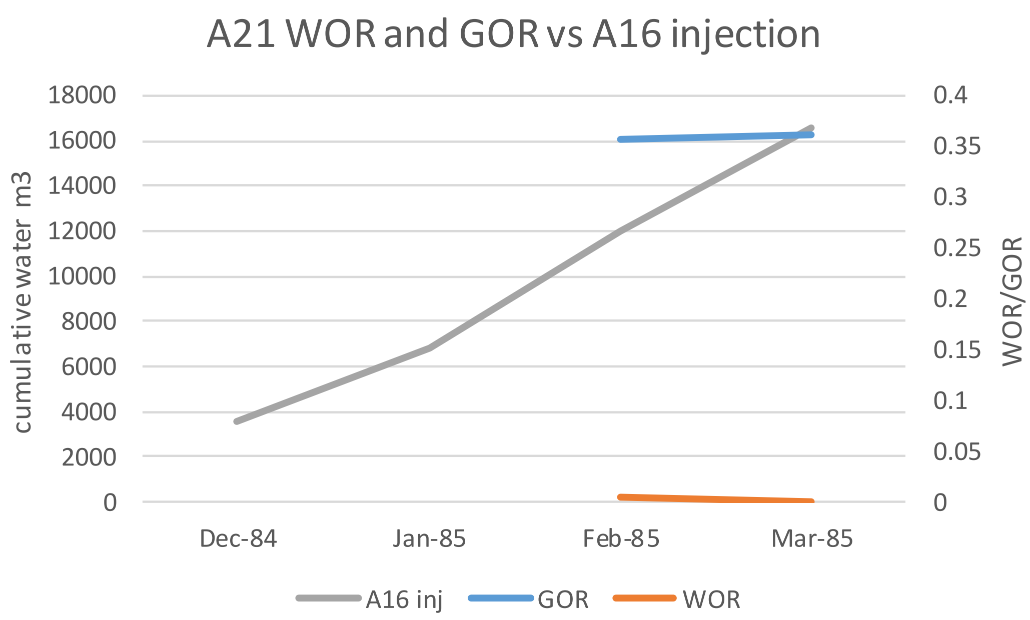


Figure 76- A21 WOR and GOR vs A16 Water Injection

4.1.7 A29

A29 was a good oil producing well, producing 5.26 mmBBLs oil.

All units below LNC have been faulted out resulting in a low net sandstone thickness, but reservoir quality is excellent. Sandbodies, particularly LNE and LNG are thick, with lack of cementation and excellent vertical permeability. Production came from LNG, UNA-B, UNC, UND, UNE-G and the top UN, with UNA-B and UNE-G flowing together. The top UN is better quality than the rest of fip3 with less shale and thick sandstone, particularly towards the top. It produced a little. LNF is interbedded shale and sandstone, with poor porosity and did not produce. RFT data indicates that the Upper Ness Member is in pressure communication. The Lower Ness Member is slightly more depleted than the Upper Ness Member, and UNA is less depleted than UNC-E.

A29 had a high initial oil rate of 4965.71 bopd, which rapidly dropped in October 1986 punctuated by increases in August 1986, February 1987 and July 1988 (Figure 77). Oil rate remained very low after January 1991, indicating oil had been swept from the permeable layers.

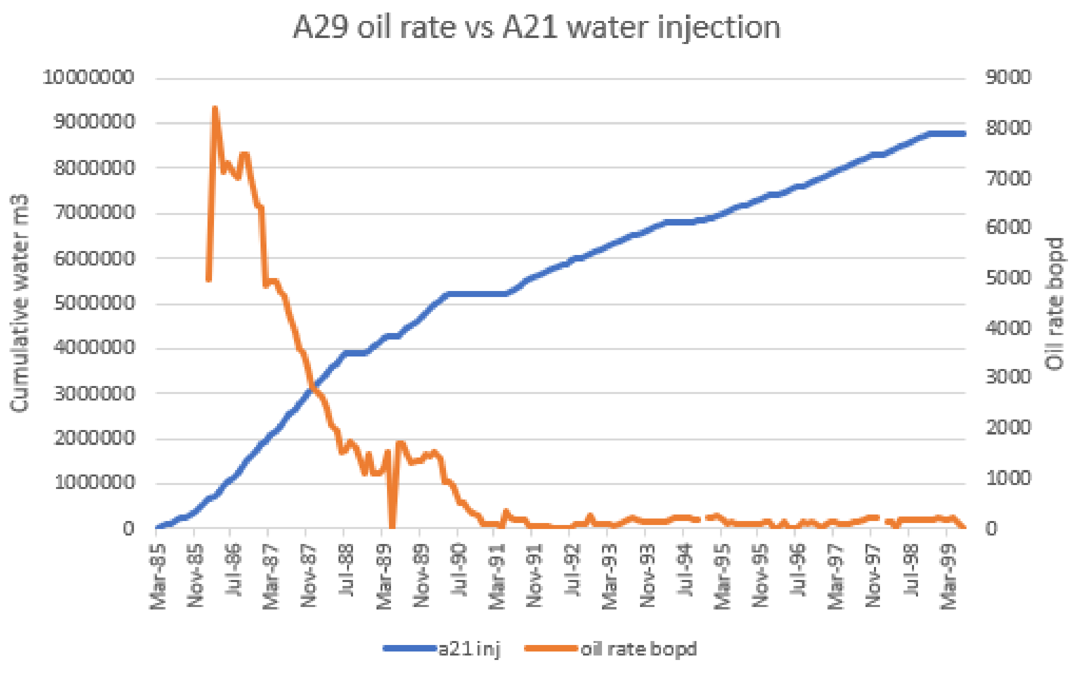


Figure 77- A29 Oil Rate vs A21 Water Injection

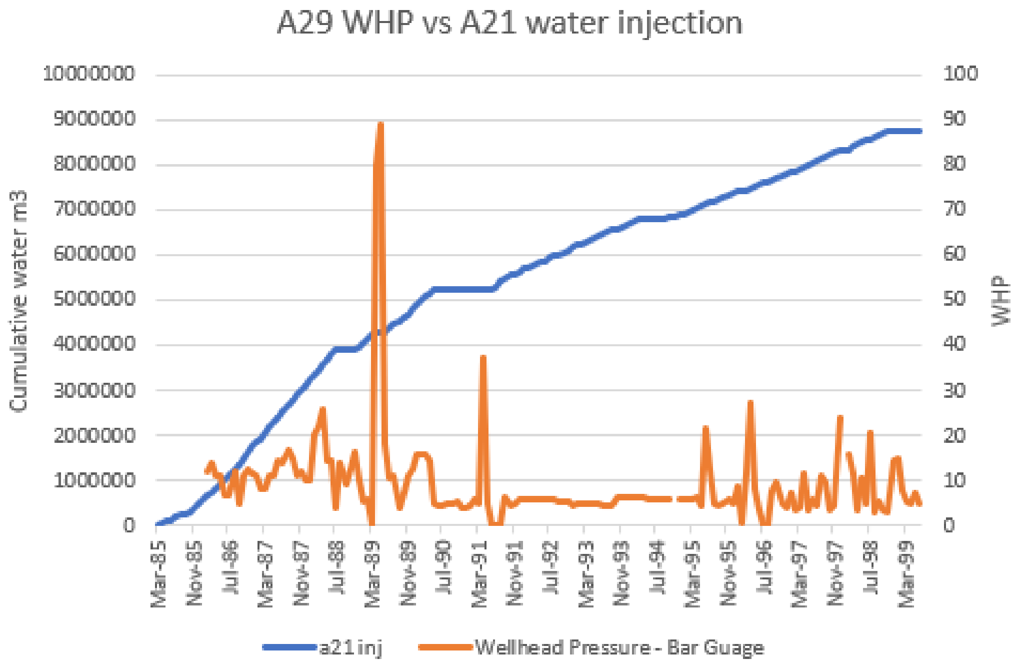


Figure 78- A29 WHP vs A21 Water Injection

WOR (Figure 79) and WHP (Figure 78) were very variable. WOR crept up between February 1987 and August 1990. GOR (Figure 79) remained low and steady, slowly increasing until March 1990. WOR decreased in April and July 1992, and oil rate remained low at this time. 20 WOR was reached in October 1993, indicating that the oil has been swept, however oil may remain in more isolated, lower permeability layers. Production was continued for 5 years and 8 months after it reached 20 WOR, where little cumulative oil was produced and pressure support continued, indicating there may not be any unswept oil. WOR decreased after it reached 20 in April 1992 and July 1992 where oil rate remained low, indicating less water was being produced at these times.

Water breakthrough from A21 is interpreted in September 1991 by an increase in WOR (Figure 79), however WOR varied a lot. GOR remained steady and low after the interpreted breakthrough, indicating continued pressure support from A21.

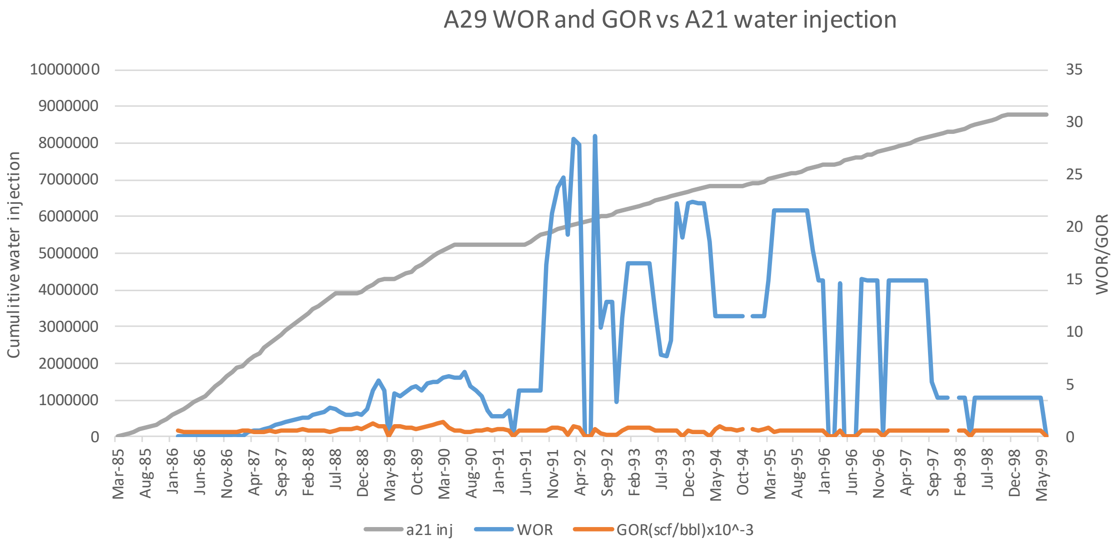


Figure 79- A29 WOR and GOR vs A21 Water Injection

A29's high oil production is attributed to the excellent quality Ness Formation and receiving pressure support from A21 along the Western Bounding Fault.

4.1.8 A32

A32 had the 9th highest net sandstone thickness and the 7th highest cumulative oil produced (1.11 mmBBL).

Sandbodies are thin and separated by abundant cement and shale, reducing vertical permeability. RFT data and the CPI log show that the Etive Formation and Upper Ness Member are compartmentalised and not in pressure communication, with the exception of UNB-C which flowed together. The CPI log show that the Lower Ness is also compartmentalised with thin sandstones separated by thick shale.

PLT data show the best producers were the UNA and UNG, thick, good quality sandstones. The Etive Formation, LND-F, UNB, UND, UNE and UNF all produced. The Broom and Rannoch Formations are below the OWC and did not produce. Only the higher permeability layers (with the exception of the Tarbert Formation) produced. There may be unswept oil in the Tarbert Formation and thin lower permeability sandstones in UNC-E which produced less.

A32 was a slow steady oil producer over a long period of time and oil production did not plateau (Figure 55). It's location between water injectors A08Z and A16 meant that it received good pressure support, an increased WOR (Figure 46) and stabilised oil rates (Figure 80).

Oil rate dropped quickly and was generally low but steady throughout production, with the decrease in oil rate slowing in April 1989 (Figure 80).

Oil rate started relatively low (3090 bopd), typical of later wells (Figure 45), as RFT and water saturation data indicates that oil had already been swept by injectors, particularly in the high permeability units the Etive Formation, LNA, UNA and the Tarbert Formation. RFT data also indicated overall depletion at A32. LNG is oil saturated indicating that this layer had not been swept, despite being of high permeability and porosity.

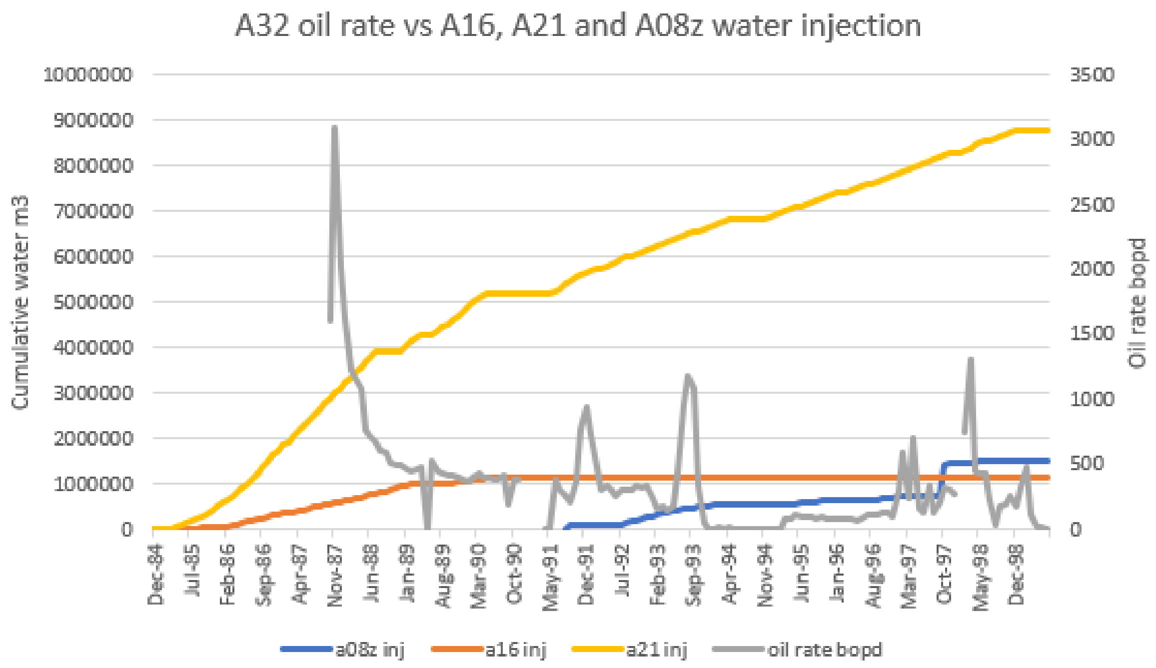


Figure 80- A32 Oil Rate vs A16, A21 and A08Z Water Injection

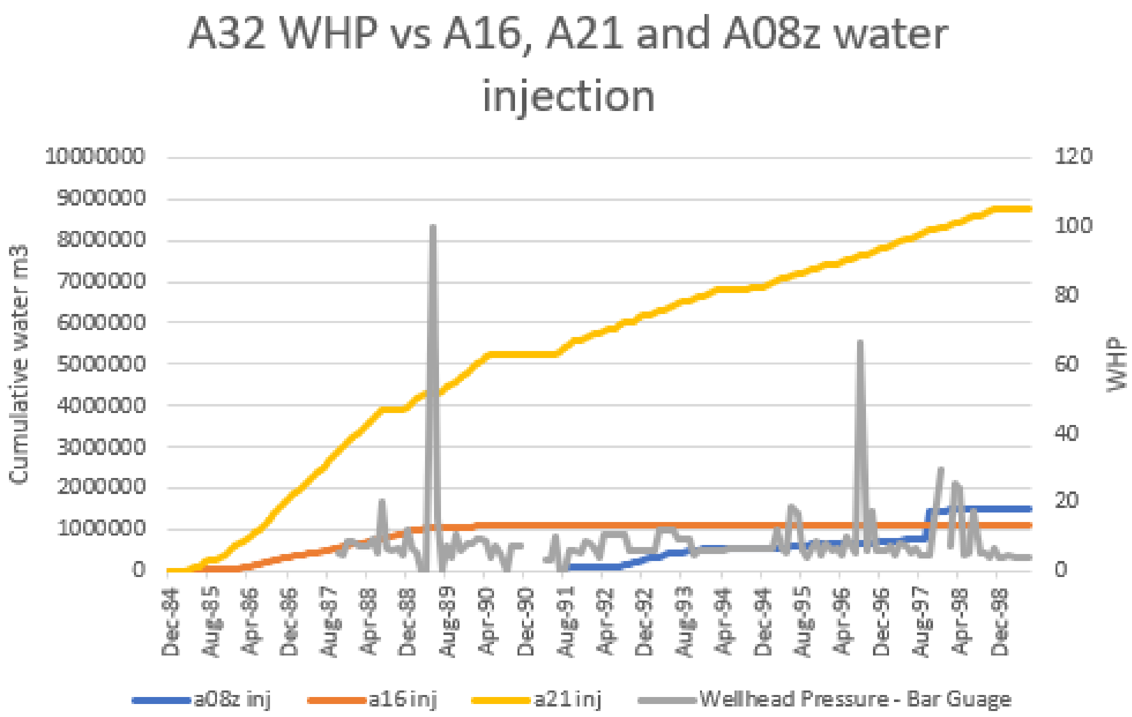


Figure 81- A32 WHP vs A16, A21 and A08Z Water Injection

A32 responded to the jump in A08Z injection in September 1997 with an increase in oil rate, WHP and WOR in December 1997(Figures 80, 81, 82 respectively). The waterfronts reached A32 before production began, resulting in the higher water saturation of more permeable layers, a pressure supported oil rate curve and high WOR ~5 for the first 5 years of production (Figure 82). Due to artificial pressure support from the start of production it is unclear if formation water was present and providing natural pressure support. WOR was very variable with a serrated appearance, possibly a data error, however another water breakthrough event from A08Z is interpreted in January 1994 (Figure 82). WOR reached 20 in February 1994 after A08Z water breakthrough. WOR reduced immediately after, however when production ends the well was at 20 WOR indicating that it was at 95% water cut and the permeable layers have been swept of oil. The Etive and Ness Formations are compartmentalised so oil may remain in isolated sandbodies despite the well reaching 95% water cut.

Its performance is attributed to a combination of higher permeability already been swept by A16 and A21 due to being on their water front paths (Figures 98 and 100 respectively), compartmentalisation, a low net sandstone thickness, and receiving good pressure support. A32 is interpreted to be pressure supported by A08Z, A16 and A21, increasing WOR and steadying oil rates. Production ended June 1999 when the field shut.

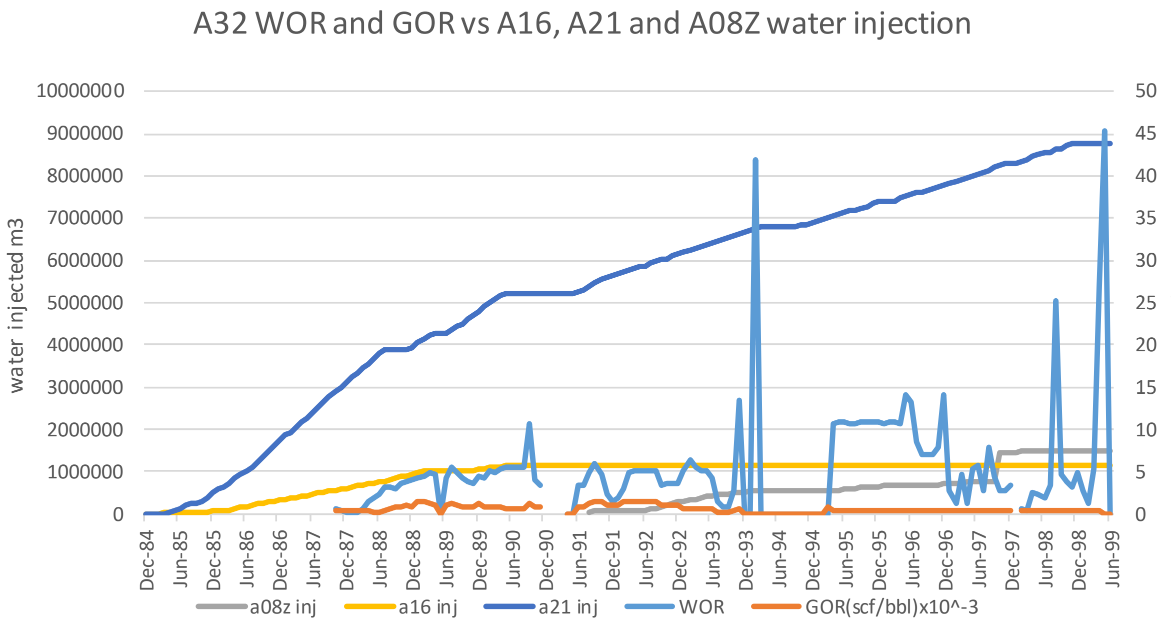


Figure 82- A32 WOR and GOR vs A16, A21 and A08Z Water Injection

4.1.9 A37

A37 is located in a fault block to the East of fip3. It is a known problem well and had a low cumulative oil of just 0.57 mmBBLs. Its reason for shut in is attributed to 'failed cleanout stopping production' (Bridge Petroleum). It has the 9th highest cumulative oil and the 7th highest net sandstone thickness, fitting the trend (Figure 11).

UNA-E was 20-30% water saturated, and the Tarbert Formation is also water saturated and highly depleted (shown by the CPI log and RFT data, Appendix). It is unlikely that these had been previously swept as there are no nearby wells to steal production and no waterfront would have broken through in the Eastern fault block before A37 began production. The water saturation of the Tarbert Formation is theorised to be the result of a perched aquifer.

A37 had a large pressure range (2078-8676 psi), and RFT data show its very vertically compartmentalised with lack of pressure communication from cementation and shales. The Lower Ness Member in particular has very poor vertical permeability, with thin, fine sandstones and shale and coal layers.

There is only PLT data for October and December 1988 which show LNE-F, UNC and UNF-G, were producing. A37 was the only well with UNA not seen to be producing, it is good quality and 30% water saturated so may have produced later. LNA-D and LNG were not producing in the timeframe shown, they are lower permeability but still have thin sandstones, so there may be unswept oil here as the area is very compartmentalised.

Oil rate was high at the start of production and rapidly decreased (Figure 83). It has a serrated appearance and varied a lot, this may be due to channels being drained. Oil rate had temporary increases in September 1988, January 1989, August 1989, May 1990 and August 1991, after which it levelled off.

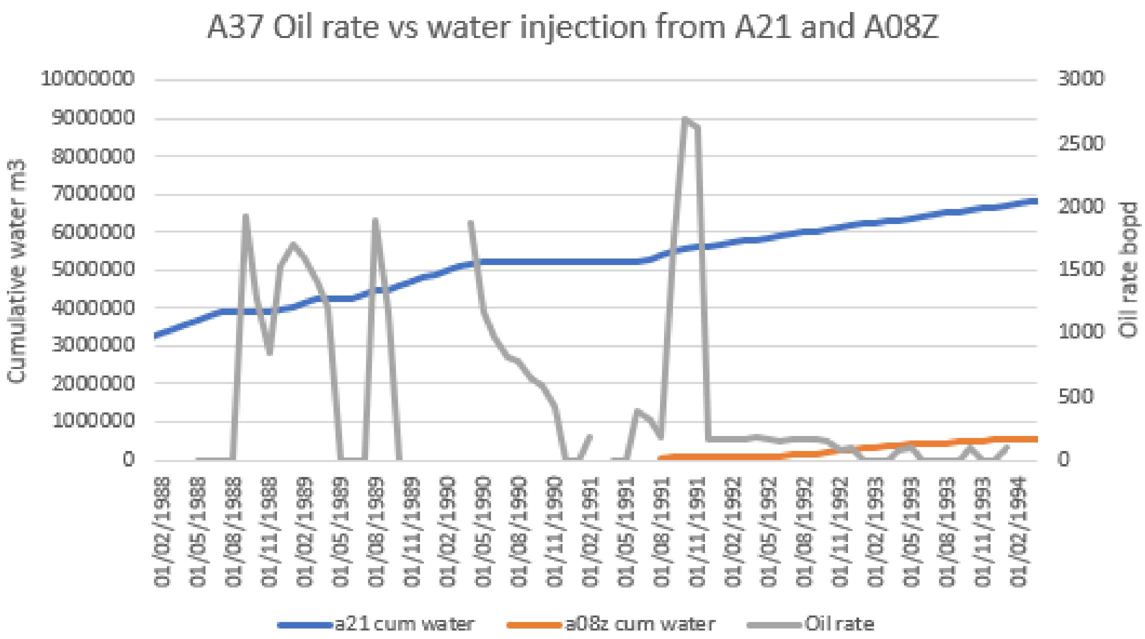


Figure 83- A37 Oil Rate vs A21 and A08Z Water Injection

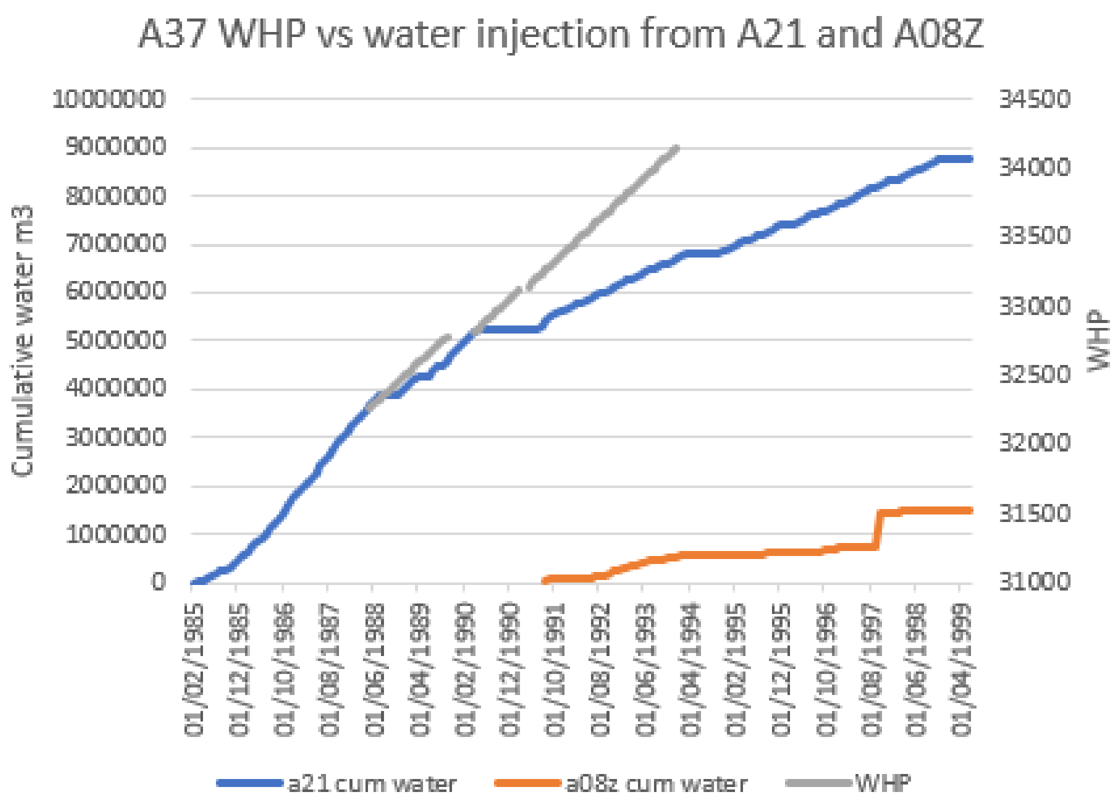


Figure 84- A37 WHP vs A21 and A08Z Water Injection

WOR crept up between November 1988 and August 1991 (Figure 85), after which it returned to its's previous rate as oil rate increased, this indicates a single channel may have been drained. There are no PLT data at this time to indicate which unit the oil was coming from. The majority of oil was produced by August 1991, however production continued until December 1993. A37 was not in close proximity to other wells and there was no stealing of production from nearby wells.

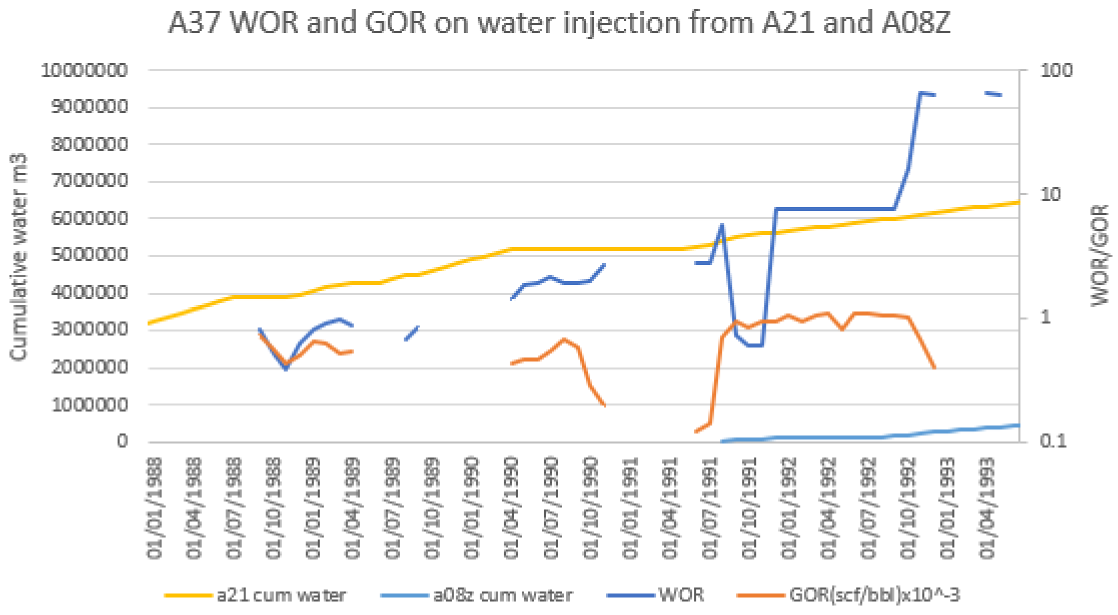


Figure 85- A37 WOR and GOR vs A21 and A08Z Water Injection

WOR increased slowly between November 1988 and August 1991 (Figure 85) indicating possible formation water support. A37 has a low elevation and a high OWC resulting in the Broom, Rannoch and Etive Formations all being water saturated. WOR decreased in August 1991 then returned to previous rate simultaneous to an oil rate increase, this indicates a single channel may have been drained of oil. There are no PLT data at this time to indicate which unit this may been. There was a huge WOR increase as oil is depleted at the end of production in September 1992. WOR reached 20 in November 1992 and increased to 66, indicating the oil had been swept. However, the eastern block of fip3 is highly compartmentalised so there may still be oil remaining in isolated, unswept sandbodies.

There is not much evidence to suggest that production of oil had pressure support from water injector A21, for this to occur the waterfront would have to travel through the fault, which may be sealing. A water breakthrough from A21 has tentatively been interpreted in September 1992, by a huge WOR increase and GOR decrease (Figure 85), after which WOR remained high. WHP did not change. The WOR increase cannot be attributed to a drop in oil rate as most of the oil had already been depleted by this time (Figure 56). Assuming the WOR jump was caused by A21 water breakthrough the relative timing would mean that it took around 4½ years for the waterfront to travel between A32 west to A37.

RFT data indicate possible pressure communication either side of the fault separating A32 and A37. Both showed similar pressures in the Broom Formation, Etive Formation, UNA, UNC and Tarbert Formation. In A37 UNG was much more depleted (3603 psi) compared to A32 (6023 psi).

A37 had a poor performance due to problems with the well, compartmentalisation, the lower net sandstone thickness and high water saturations. However, it received sufficient pressure support from higher aquifer and possibly from A21 injection. The rock is highly compartmentalised meaning that there is likely oil remaining despite the well reaching a very high water cut.

4.1.10 A40

A40 had the 6th highest net sandstone thickness and the 8th highest cumulative oil production (0.96 mmBBLs) in fip3, this fit the trend of a higher net sandstone thickness producing more oil.

As a late well on A21's water injection path (Figure 100), many layers were partly swept; the Rannoch and Etive Formations were 30-80% water saturated and depleted. Sandbodies in the Ness Formation (LNB-LND, LNG, UNG) were 10-100% water saturated. RFT data show that A40 is very compartmentalised and not in pressure communication, with the Broom Formation, Etive Formation, Upper Ness Member and Tarbert Formation all very depleted.

The poor quality, highly compartmentalised Lower Ness Member and high water saturations of the Etive and Rannoch Formations mean that only the Upper Ness Member and Tarbert Formation produced significant quantities of oil. The Upper Ness is good quality. UNG in particular is thick with excellent porosity and permeability but was partially water saturated.

PLT data are only available for August 1989 and September 1991. Production came from UNA-B, UNC, UNG and the Tarbert Formation and minimal amounts from LNA-F. The Etive Formation and LNG were not shown to be producing despite being permeable, however they (and other units) may produce later on where there is no PLT data.

A40 had a higher initial oil rate (2760 bopd) than other late wells (Figure 45), likely due to good pressure support, however, was shut in due to high water presence and severe scaling (Bridge Petroleum). Oil rate dropped rapidly (Figure 86), is unsteady and there was little oil production after November 1990. As oil rate dropped WOR and GOR rapidly increased (Figure 88).

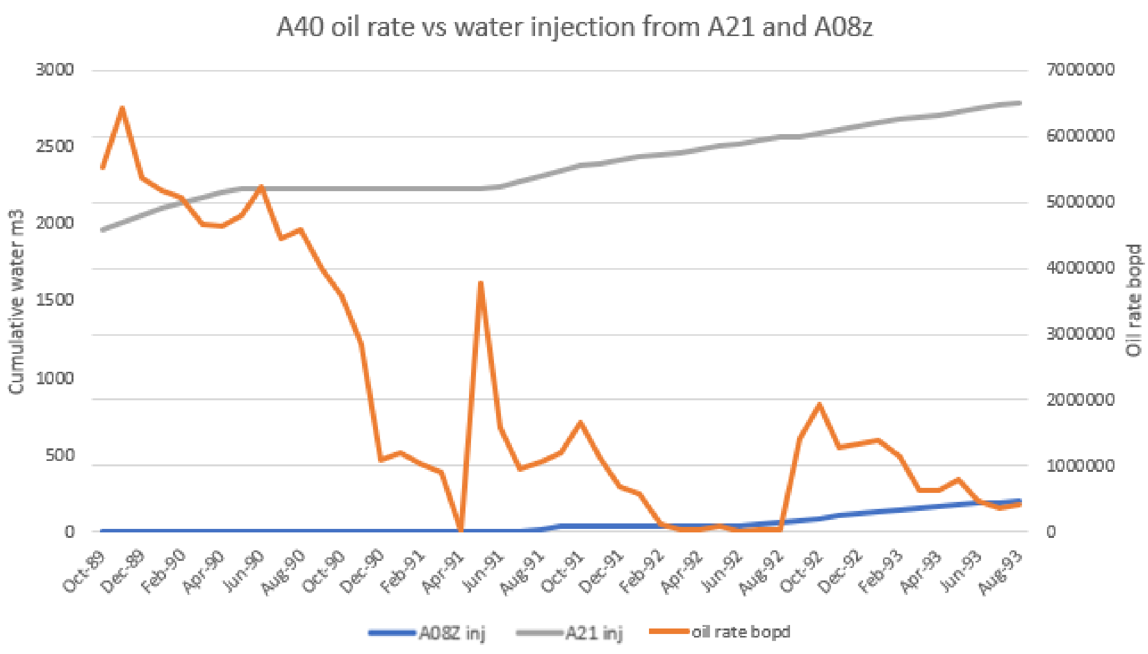


Figure 86- A40 Oil Rate vs A21 and A08Z Water Injection

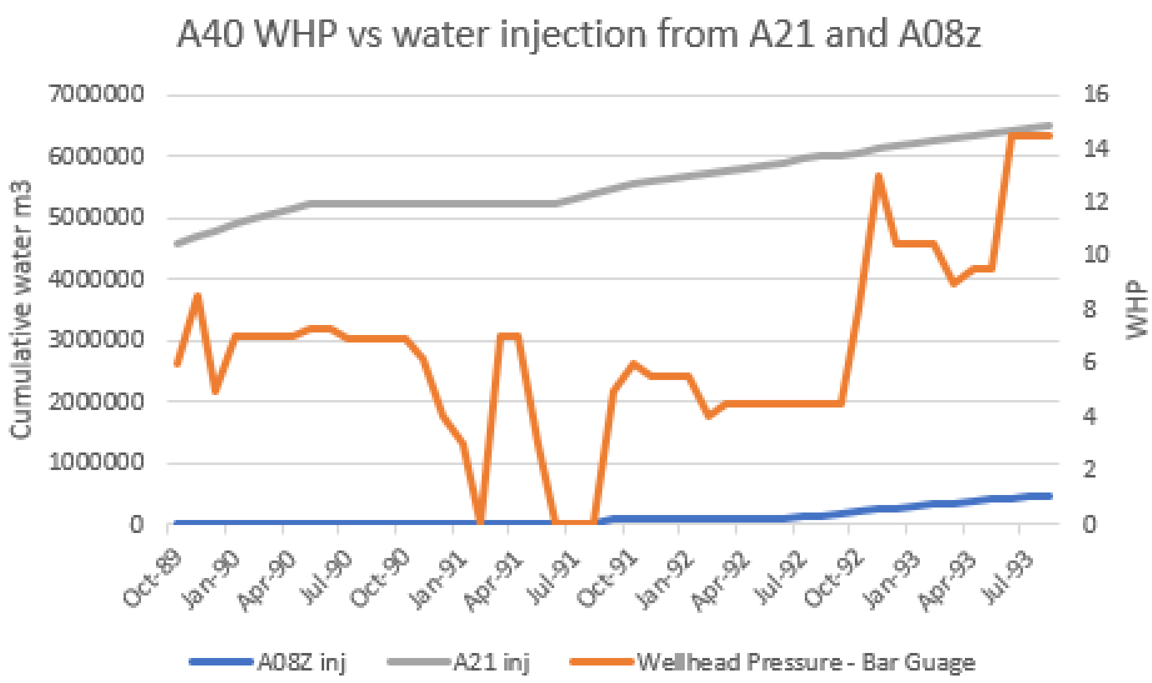


Figure 87- A40 WHP vs A21 and A08Z Water Injection

Generally, WOR and GOR mirrored each other (Figure 88). WOR drastically increased to ~30 as cumulative oil was reached. WOR increased in November 1989 and February 1992, where oil rate was low and WHP steadied. WOR also increased in February 1993 as oil rate and WHP decreased simultaneous to A08Z injection. A21 water breakthrough is interpreted to have occurred before A40 began production, due to the rapidly increasing WOR from start production, a high initial oil rate that gradually declined and water saturated units.

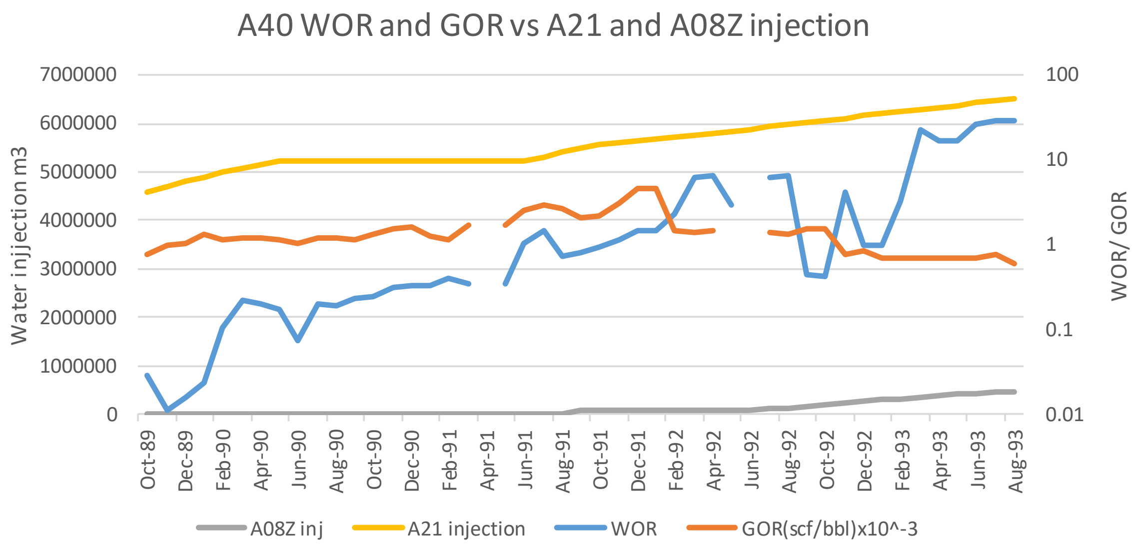


Figure 88- A40 WOR and GOR vs A21 and A08Z Water Injection

The timing also fits when mapping A21's waterfront travelling south (Figure 100). It is unclear if formation water is also providing pressure support, A40 is located nearby to an inferred pool of water (Figure 37) and the OWC is high in the area (ODT 11733ft). Oil rate levelled out after November 1990, as oil rate decreased WOR increased. Between April and May 1991 there was a temporary spike in oil rate and WHP indicating an isolated channel was being drained. There is no WOR or GOR data for this time, or PLT data to indicate which unit this may be.

Water production was steady, with the rate increasing in September 1992 (Figure 57). WOR was highly variable. Water breakthrough from A08Z is interpreted in January 1993 by a rapid increase in WOR and decrease in oil rate where GOR remained low (Figure 88). WOR increased to 28 in August 1993. As 95% water cut was maintained the permeable layers are likely swept. There may be potential in the sandbodies of the Etive Formation and the Lower Ness, but PLT data are limited so it is unclear if the sandbodies were producing at a later date.

Its poor performance can also be attributed to it being a late, partially swept well and the rock is compartmentalised.

4.1.11 A41Z

A41Z performed well, despite being a late well in an area that was partially depleted.

A41Z began production at the same time as A48, both are in the NE fault block, however A41Z performed a lot better, producing 2.99 mmBBLs oil compared to A48's 0.07 mmBBLs. A41Z has relatively high net sandstone thickness (284.7ft), similar to that of A48 (340ft). A41Z has better quality, less compartmentalised reservoir rock compared to A48, particularly the Etive Formation and Lower Ness Member.

Only the UNA, UND, UNE and the Tarbert Formation are shown to have been producing from PLT data. There was no production from the Broom Formation, Etive Formation and Lower Ness Member despite being perforated and oil saturated with good porosity and vertical permeability. However, PLT data are only available for February 1991 so these units may have produced later on.

A41Z is more oil saturated than A48, but less than nearby earlier wells A15 and A29. The area was indicated to be partly depleted due to being on the sweep path of A21 water injection (Figure 100). The best flow units LNG and UNA (and also LND-F and UNA-G) are partly or fully water saturated, indicating that the waterfront from A21 travelled through these permeable sandstone units. The Etive Formation, LNC and the Tarbert Formation are relatively oil saturated indicating the waterfront did not sweep these layers, despite still being permeable. RFT data indicates that the Ness Formation is in pressure communication and is more depleted than the Etive Formation. The Tarbert Formation the most depleted layer.

Oil rate was similar to the initial oil rate of A03Z (Figure 45). The graph of oil rate (Figure 89) has a serrated appearance, with rapid but unsustained increases in April 1994, September 1986 and February 1998, interpreted to be the draining of isolated channels. There are no PLT data at this time to indicate which units were being depleted. Oil rate was still high when production was shut off, indicating there is still unswept oil in the area.

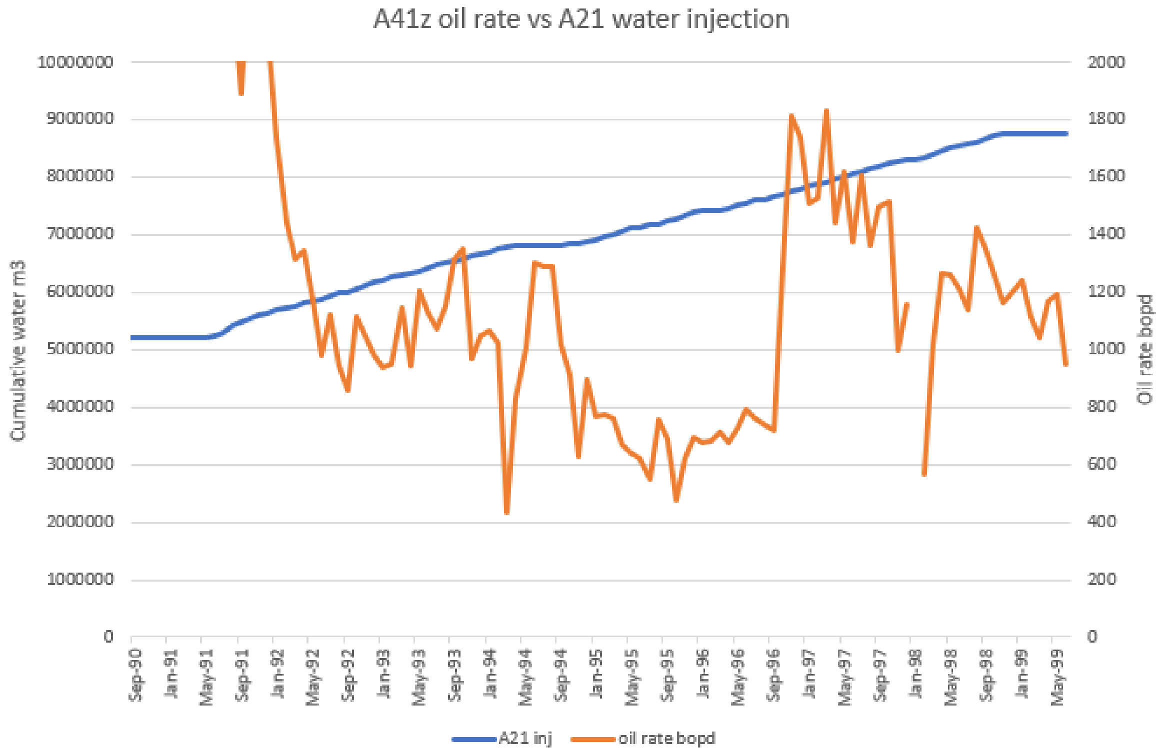


Figure 89- A41Z Oil Rate vs A21 Water Injection

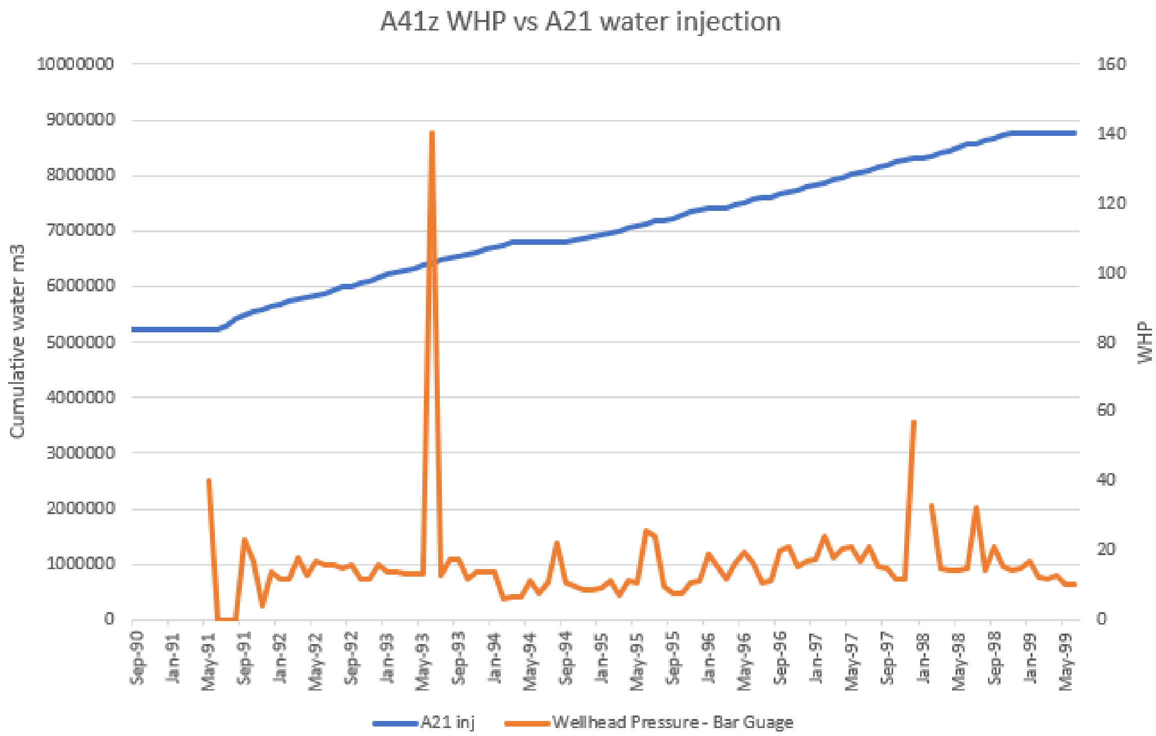


Figure 90- A41Z WHP vs A21 Water Injection

The well had the highest cumulative water production (Figure 44), with rapid water production from the start of production at a similar gradient to A21 water injection.

A41Z had an increasing and high WOR, typical of later wells (Figure 46), at the start of production in May 1991, similar to other later wells. WOR was very variable (Figure 91), sensitive to the fluctuating oil rate. There were 2 major increases in WOR in May 1991 and January 1993.

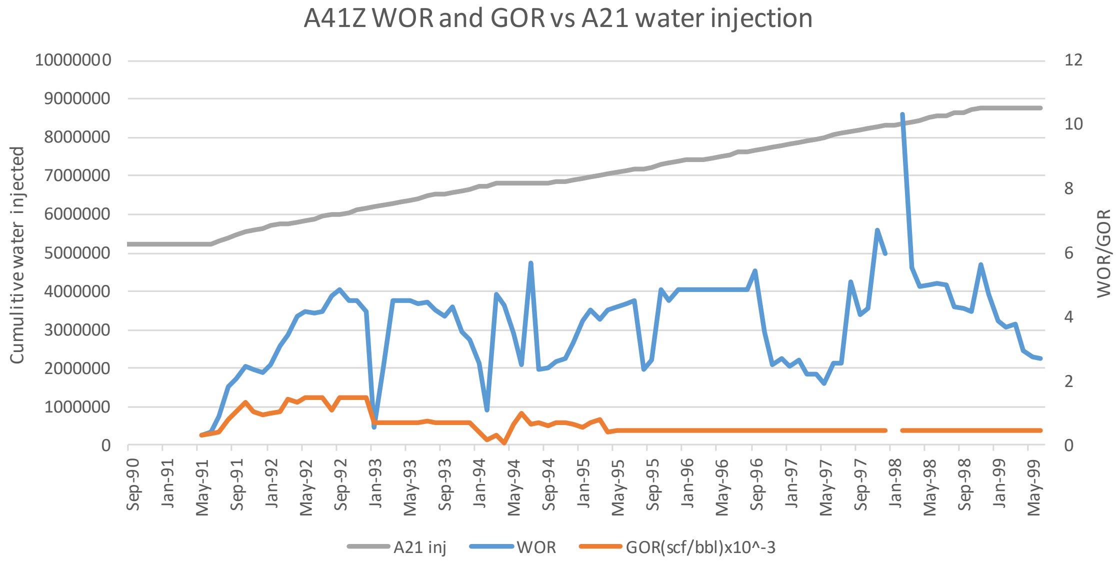


Figure 91- A41Z WOR and GOR vs A21 Water Injection

A41Z was on the sweep path of A21 (Figure 100) and received good pressure support from start production, evidenced by the high initial oil rate (10518 bopd, similar to the starting oil rate of A03Z), steady and high WHP, high WOR and decreasing GOR. A41Z produced the most water in fip3 and at a rapid rate which matched the gradient of A21 water injection (Figure 44).

4.1.12 A48

A48 is geographically close to A15 but had a significantly lower cumulative oil of just 0.07 mmBBLs.

Reservoir quality is average (excluding the base Lower Ness Member, which had no porosity or permeability) with not much compartmentalisation and a high net san of 340ft, this does not account for the poor well performance. Resistivity and density logs show a lot of good porosity rock filled with hydrocarbon. LNA-D is poor quality with no porosity or permeability. There is no RFT data for A48 to analyse depletion and compartmentalisation.

A48 had a high water saturation particularly in LNG and UNA, which are typically the layers in fip3 with the highest permeabilities and porosities that would be swept first. These layers are interpreted as having been swept by A21 water injection prior to A48 coming on production. UNG and the Tarbert Formation had the higher oil saturations (70-90%), these layers produced well on PLT, lots of oil likely came through these units.

PLT data are only available for May 1991, production was from LNA-E (despite not being perforated), UNA, UNE-G and the Tarbert Formation. LNE and the Tarbert Formation produced the most. LNA-E has poor rock quality and very little net sandstone. LNG has thin shale layers reducing vertical permeability and is 10-80% water saturated and did not produce.

The majority of oil production occurred in the first month (Figure 59), but production was continued for a further 22 months, with water production and water cut increasing. Oil rate was typical of later wells and rapidly dropped and remained low (Figure 92), with 3 small increases likely due to the draining of channels in September 1991, June 1992 and November 1992. 95% water cut was reached in August 1991 after 4 months production.

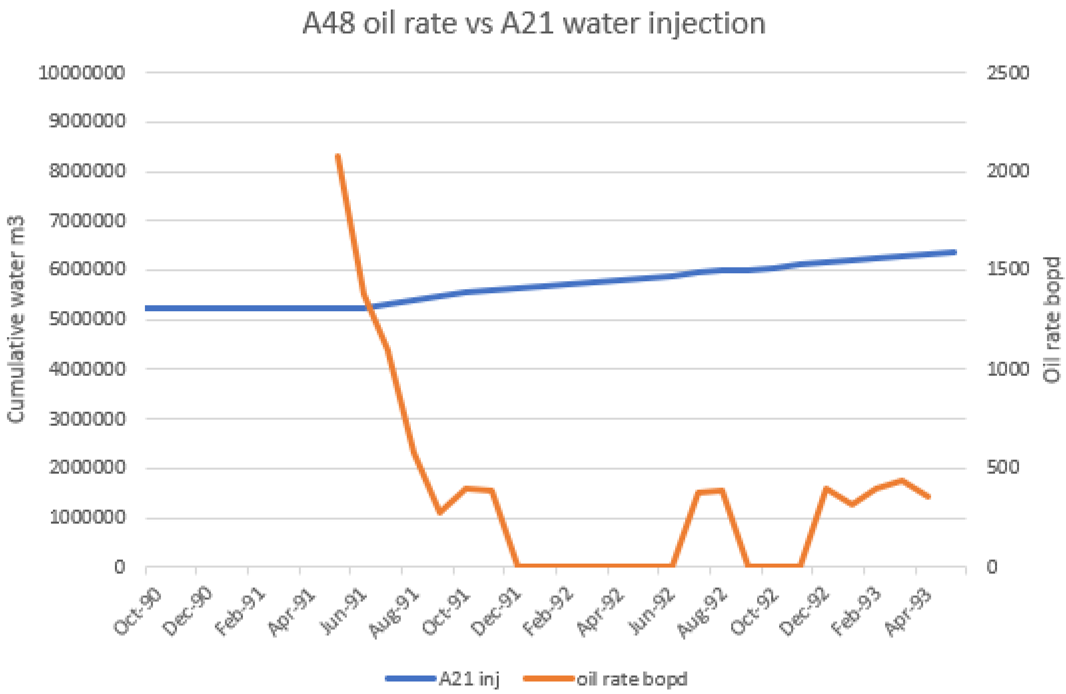


Figure 92- A48 Oil Rate vs A21 Water Injection

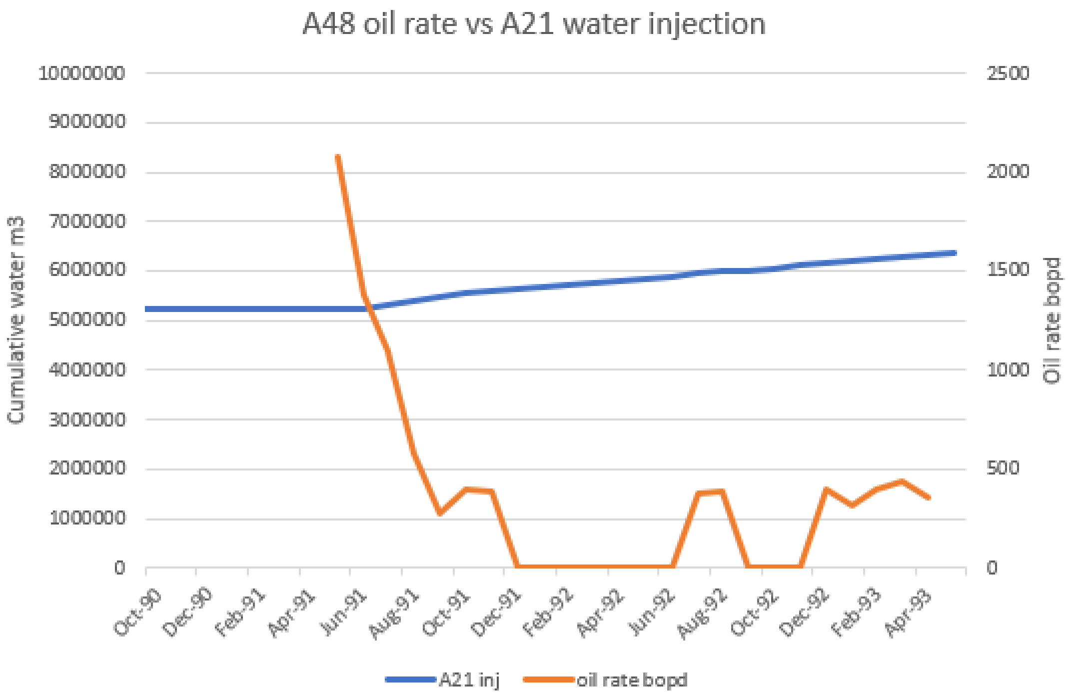


Figure 93- A48 WHP vs A21 Water Injection

WHP had an initial spike in August 1991 (Figure 93), but immediately decreased as GOR increased (Figure 94), after which WHP was steady.

A48 had the highest starting WOR of 3.1. A15 and A29, nearby wells have similar WOR at their end of production (4.5 and 2.5), indicating the area is depleted (Figure 46). 20 WOR was reached in August 1991, after 4 months of production, and was steady after (Figure 94). In July 1991 GOR and WOR increased as WHP and oil rate rapidly decreased. A48 is indicated to be pressure supported by A21, with water breakthrough occurring in July 1991 (Figure 94).

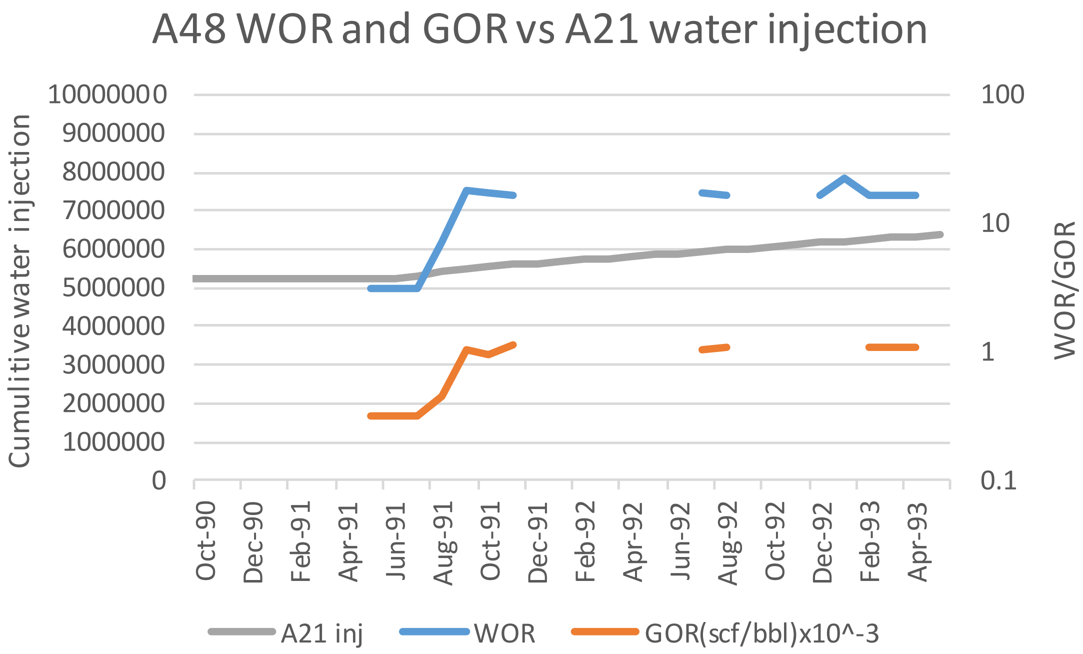


Figure 94- A48 WOR and GOR vs A21 Water Injection

A48's poor performance was unlikely to be controlled by rock quality, but by being a late well in a depleted area on the water injection path of A21 (Figure 100).

4.2 Pressure Support

4.2.1 Natural Pressure Support

Formation water has been indicated to provide pressure support in fip3. WOR gradually increasing before water breakthrough events has been observed in A03Z, A08Z, A14 and A37, indicating the presence of formation water. It is unclear if natural pressure support is occurring in wells producing over a short time frame (A16 and A21), or in later wells where water breakthrough is interpreted to occur before production begins (A32, A40 and A48).

A pool of water has been interpreted in the structural low to the south of fip3 (Figure 37), providing a little energy from formation water support in the area to A08Z, A14 and A40.

4.2.2 Water Injection

As wells age water production outstrips oil production. Injection of (sea) water maintains pressure within the reservoir, displaces oil towards production wells and ensures that pressure does not drop below the bubble point. (Gluyas et al, 2010). Although pressure can be maintained indefinitely, sweep cannot. This is demonstrated in fip3 by a sharp increase in WOR without addition of significant volumes of oil. On the pathway between injection and production wells the oil on the flow pathway is reaching irreducible oil saturation.

The best flow units are the highest porosity and permeability layers with good connectivity that are laterally extensive and not compartmentalised. Due to the heterogenous nature of fip3, the best flow units are often channels in the Ness Formation, despite being thin and isolated. The Etive Formation and UNA are of sheet sandstone geometries and have better lateral connectivity than channel sandstones. As the sandstones are of sheet like geometries and lack erosion or amalgamation surfaces, they do not connect with the overlying and underlying units so injected water may not reach these, and they may remain unswept if they are not directly connected to an injection well. Injection water has been indicated to travel long distances through the Upper and Lower Ness sandstone prone channels in fip3 and significant pressure declines have been observed within the Upper Ness sandstones. In the NE block injection water from A21 is interpreted to travel through UNA (largely in pressure communication, with the exception of A15 which is less depleted), shown to produce more after water breakthrough, or being depleted or water saturated. LNG is similarly depleted to UNA throughout fip3 indicating the waterfront also travelled through this unit.

A21 provided the best pressure support throughout fip3 and injected by far the most water (Figure 42). Injection rate was maintained over time, whereas the initial rates of A08Z and A16 plateaued after a few years. A08Z is in a compartmentalised area, so injected fluids would be baffled and have more tortuous routes to sweep sandstones. A21 and A16 are in areas of better rock quality, however A21 has a higher net sandstone thickness of 333ft compared with 225ft (Figure 11), which may have contributed in A21's better performance. All injectors are at a similar elevation, however A08Z is close to the water pool interpreted at the south of fip3. The higher pressure in this area, and the fact that A21 injector support had already reached the south may have resulted in a smaller pressure gradient resulting in A08Z injecting less water.

In fip3 injector paths were mostly interpreted to travel south and north, parallel to the main fault orientation (Figures 96, 98 and 100). A21 on the Western Bounding Fault received good pressure support, however faulting can also slow or stop the waterfront such as with the eastern fault block of fip3.

4.2.2.1 A08Z

Injected water from A08Z is interpreted to have reached A40 in January 1993, A32 in January 1994 and A14 in February 1994 (Figure 95) and taking 30 months to reach the south of the fip3 (Figure 96).

A08Z had the slowest starting rate of injection, indicating lower pressure in the area. Injection had a sudden increase in September 1997. The cause of this is unclear, there are no PLT data from this time to investigate if the injection may be reacting to a perforation where it may suddenly take in fluid and back up in pressure. This may be simply an operational or data error or a new lower pressure sandbody sucking in the water. There is no evidence for this in surrounding wells A14, A32 and A40. A32 responded to A08Z's increase in water with an increase in production 2 months later.

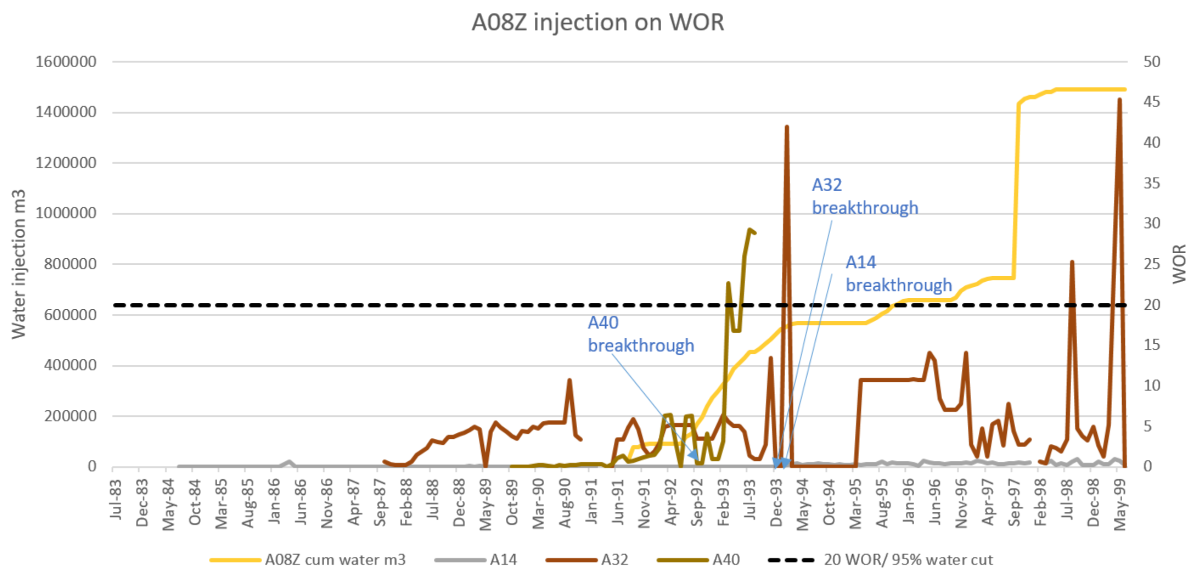


Figure 95- Interpreted Water Breakthrough Times of Water Injector A08Z on Wells in fip3

Figure 96- Water Injection Paths of A08Z, with Water Breakthrough Dates

4.2.2.2 A16

There is evidence of A16 pressure support reaching A03Z and A32 in July 1986 and March 1988 respectively (Figure 97). The waterfront took 19 months to reach A08Z from start injection in the highly cemented and compartmentalised west of the fip3 (Figure 98). It had reached A32 before it began production, so it is unknown how long it took for the water to travel from injector to producer. There is no evidence of A16 providing pressure support to the NE fault block, despite the fact that the fault is not indicated to be sealing.

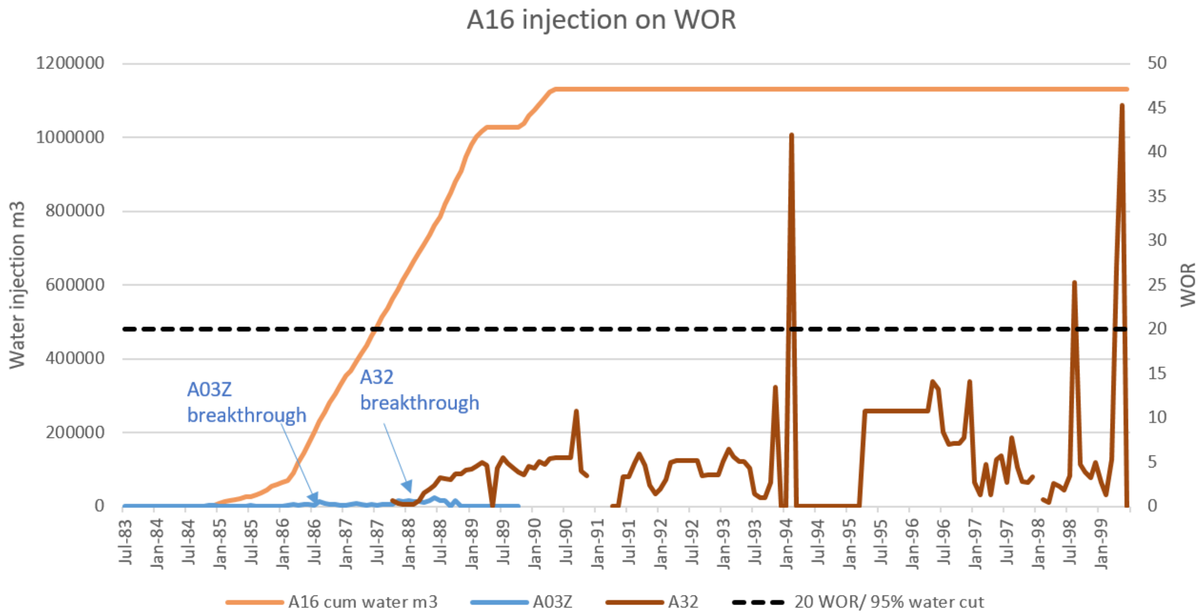


Figure 97- Interpreted Water Breakthrough Times of Water Injector A16 on Wells in fip3

Figure 98- Water Injection Paths of A16, with Water Breakthrough Dates

4.2.2.3 A21

The rate of water production was the fastest in the initial 3 years, before 3 'steps' and slowing (Figure 99), likely due to a lack of injection caused by operational problems.

A21 water injection reached all wells in the NE sector; A48 (predating the start production), A15 (January 1987), A41Z (July 1991) and A29 (September 1991) (Figure 99). Water would have been dragged to A15 when the injection began, with some at least partly bypassing A48, then as A29 was switched on and pressure became depleted the waterfront was dragged there by the pressure gradient. A48 and A41Z were likely drilled into the known waterfront (Figure 100) for a high likelihood of good pressure support. The waterfront travelled through the fault separating the NE sector from the main sector of fip3, indicated not to be sealing with evidence from RFT data of pressure communication either side. The waterfront travelled south through fip3 to lower pressure areas, with breakthrough occurring in A32 (pre start production), A08Z (January 1988), A40 (pre start production) and A14 (January 1989), taking 46 months to reach A14 in the south (Figure 100). In the NE sector of fip3 LND-G, UNA-C and UNE are commonly water saturated, so the waterfront has been interpreted to have travelled through these permeable channel and sheet sandstones.

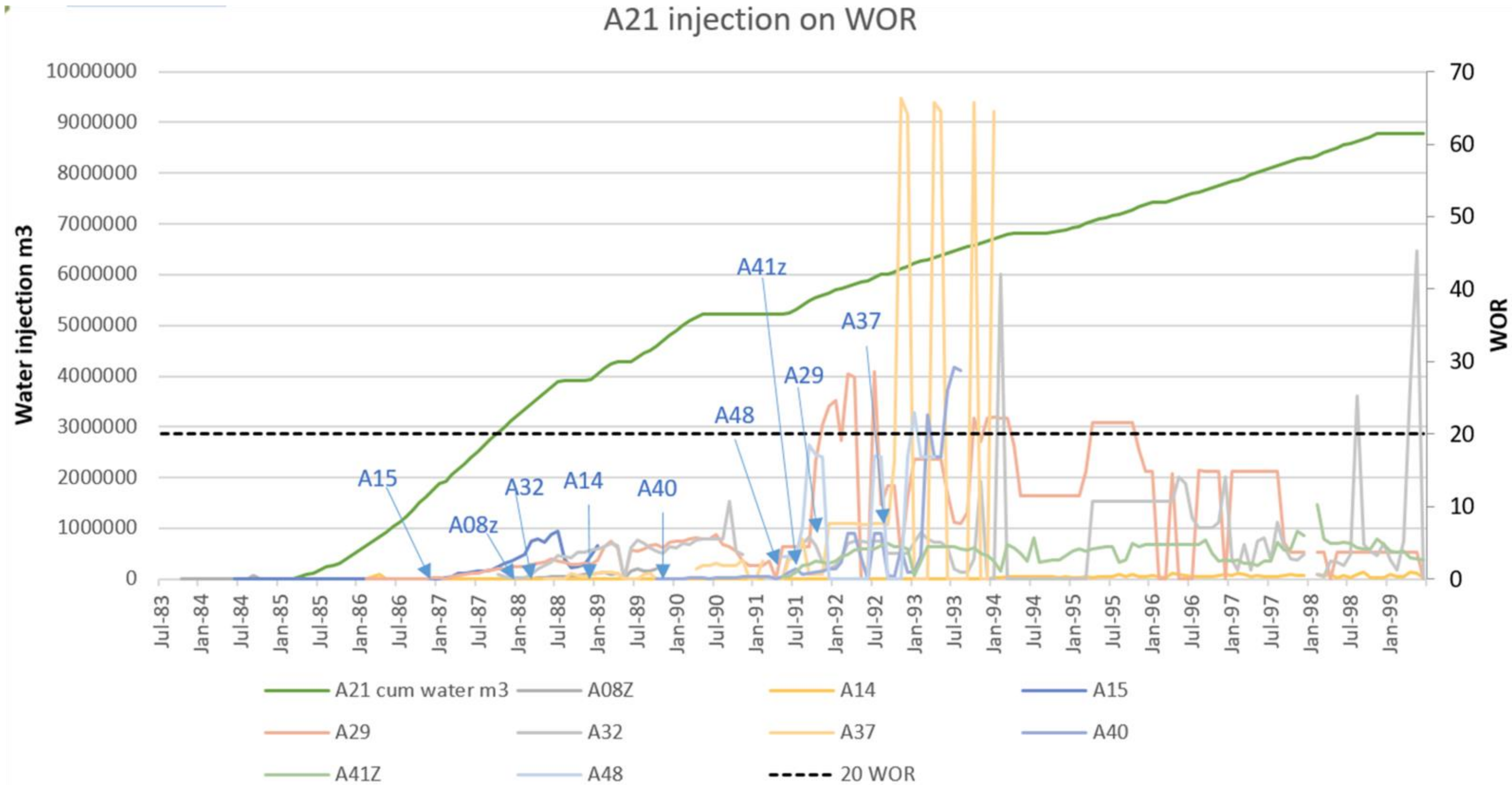


Figure 99- Interpreted Water Breakthrough Times of Water Injector A21 on Wells in fip3

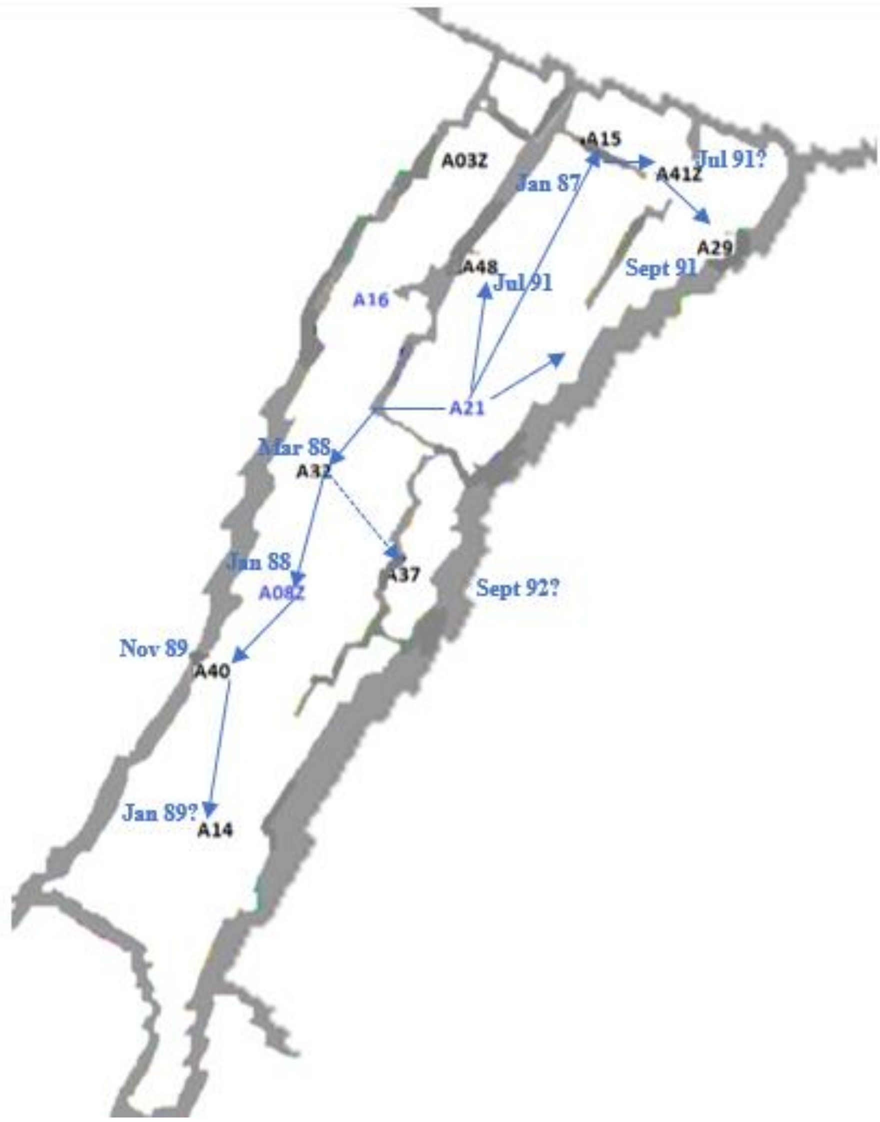


Figure 100- Water Injection Paths of A21, with Water Breakthrough Dates

4.3 Discussion

4.3.1 Overall Well Performance

Wells drilled early in the development of the field generally produce more oil than those drilled later. This is due to

1. Oil not yet being swept. This is evident in A41Z and A48 being water saturated and depleted as they were later drilled into existing flood fronts where the oil has already been swept from some units.

2. Higher pressure resulting in higher oil rates. RFT data show that early wells are at virgin pressures when drilled, whereas the later wells were more depleted.

3. A lack of operational issues, such as scaling, which develop over time. By field shut in the more permeable sandstones had watered out and water flowed into unswept lower quality sandstones, resulting in barium sulphate precipitation near wellbore in unswept sandstones (Gluyas et al, 2020). Solids precipitated in the near wellbore region and in the production facilities can cause serious problems limiting production and injectivity (Gluyas et al, 2020).

Initial oil rates in fip3 were high due to the highly permeable channel sandbodies in the Ness Formation, but production rates rapidly dropped as these channel bodies were drained. Complex compartmentalisation meant that many oil bearing sandstones did not produce. In NW Hutton most wells had a build-up of production, followed by a drop in oil rate, initially rapid then levelled off at a low rate. There was not a defined or sustained plateau period, which is typical of a North Sea field oil production profile (Gluyas et al, 2010).

Within fip3 wells which produced more oil generally produced more water. There is a clear geographical control on well performance observed in bubble maps (Figures 38-41) due to rock quality, compartmentalisation and net sandstone thickness varying throughout fip3.

The oil rate of A08Z decreased as A32 started oil production, indicating poor well placement in fip3 where newer wells are drilled too close to existing wells where the new well "steals production" from the older well. A48 and A15 were not on production at the same time but are in close proximity, and A48 starting oil rate is similar to the rate at the end of A15's production, indicating that A48 was drilled too close in an already swept area. Where wells have been drilled into existing flood fronts (A41Z also shows evidence of this) most of the oil has already been swept. "Stealing of production" may occur in other wells but is difficult to identify as the oil rate was already very low (such as A29 when A41Z comes onto production), or there is no temporal overlap.

Reservoir quality and net sandstone thickness are also strong controls on well performance. Wells with a higher net sandstone thickness in fip3 generally produced more oil (Figure 11). This, however, does not reflect compartmentalisation so individual rock quality has been studied on a well per well basis in chapter 4.6.

4.3.2 Facies as a Control on Reservoir Quality

From porosity and permeability data it can be concluded that facies have a strong control on reservoir quality (Figure 13). Depositional environment, along with faulting, control the geometry, architecture and connectivity of sandbodies.

Six main facies associations form the reservoir quality rock in fip3: fluvial multi/ single storey channels types A and B, distributary channels and mouth bars, tidal shoals and shoreface sheet sandstones. These comprise ~60-80% of the sandstone rich sequence and are layered with the non reservoir facies associations. The non-reservoir facies act as permeability baffles and include bay margin and bay margin heterolithic, fluvial floodplain mud rocks and distal bayhead delta.

The reservoir facies associations with the highest permeabilities and porosities (Table 6) are fluvial channel type B (K=445.5mD, ϕ=0.192), distributary channel (K=140.6mD, ϕ=0.201) and tidal shoal (K=202mD, ϕ=0.187). The latter is a laterally extensive sheet sandstone, RFT and PLT data indicate that injection water travelled through this unit, particularly UNA.

Differences in provenance from the fluvial channels (primarily in the Ness Formation) and coastal complex deposits (dominant in the Rannoch and Etive Formations, subordinate in the Ness Formation), may cause the former to be coarser grained with lower primary mica and clay contents (TAQA, 2016).

Higher clay and mica contents are associated with tidally influenced depositional facies. There is a strong correlation between finer grain sizes and higher clay and mica contents because these reflect the depositional energy at the time of deposition (TAQA, 2016).

Middle shoreface, fluvial channel type A are considered reservoir facies associations, however their permeabilities and porosities are lower (K=96.69mD, ϕ=0.144 and K=8.257mD, ϕ=0.142 respectively). Permeability of fluvial channel type A are up to 2 orders of magnitude lower than type B (Dundas, 2014). There is therefore a risk of the waterfront bypassing the lower permeability upper bar facies, despite being oil bearing.

Crevasse splay sandbodies within the fluvial floodplain (dominant in the top Upper Ness Member) have high permeability and porosities but are thin and isolated within the non reservoir facies, limiting crossflow meaning these often remain unswept. There is a possibility that crevasse splay sandstones may form fluid- flow linkages between channels, increasing connectivity, but due to being very fine grained, commonly with muddy interbeds they would not serve as efficient flow units (Flint et al 1998).

Sandstones from the bayhead delta facies association have a permeability of 2.533mD, higher than the permeability of fluvial channel type A (0.164mD). Bay margin heteroliths have a similar permeability and slightly lower porosity (K=2.291mD, ϕ=0.117).

4.3.3 Stratigraphy

The permeability architecture has a strong control on the dynamic behaviour of the field. The reservoir in NW Hutton is a heterogeneous and anisotropic complex of paralic sandstones interbedded with non-reservoir lithologies. This results in the injected water bypassing significant volumes of oil in low permeability units and higher permeability units that are not or only poorly connected with the sandstones into which the water was injected. This in turn leads to rapid water breakthrough in well interconnected high permeability sandstones and rapid rises in the WOR seen in production wells. The high permeability sandstones in fip3 are within the Etive, LNG and UNA intervals.

Sandbody geometries and dimensions of channels and valley fills in the Etive and particularly the Ness Formations are highly variable, reflecting localised controls on sediment distribution and regional effects including sediment supply, basinal processes and fault block subsidence (Livera, 1989). Regular drowning events on the delta plain created a strongly layered, vertically and laterally heterogeneous reservoir of sandstones, muds, shales and coals, further compartmentalised by post depositional cementation. Laterally extensive and sheet like architectures are rare in the Ness Formation, however more sheet sandstones are found in the Lower Ness Member, whereas the Upper Ness Member is more channelized. In fip3 fluvial channels have been estimated at a common range of 10-300m wide, laterally restricted, often isolated and commonly at right angles to faults, meaning that oil was quickly depleted from these channel sandbodies.   The Ness Formation sandbodies are difficult to correlate as multi-storey channels may erode into each other.

The Etive Formation is a major reservoir unit, interpreted as distributary channels separated by interfluve at A21 and A48, revealing the progradational top of the Rannoch Formation. The channels either side of the interfluve are not indicated to be in communication by RFT data. There is limited connectivity perpendicular to flow direction (Dundas, 2014)

4.3.4 Reservoir Quality

Rock quality is high in the NE block of fip3, sandbodies (Etive Formation, LNA, LNC, LNE, UNA, UNC and UNE) are thick, shales are thin and there is little cementation as the area is up-dip, so the area is less compartmentalised. There are few faults. The NW of fip3, at A03Z, has high rock quality, with a particularly thick Rannoch Formation, LNG, LNE, UNA, UNC and top Upper Ness. To the south, sandstones are good quality, however they are thin (LNA, LNC, LNE, LNG, UNA, UNE and UNG), with the exception of the Etive Formation, which thickens to the south. Shales are thin in the area. The OWC is high so the lower units are water saturated. The fault block to the east (containing A37) has poor quality rock with thick shales and cement, however UNE is particularly thick.

The west of fip3 is more compartmentalised due to more faulting and cementation here as the Brent Group is buried deeper. There is commonly increased diagenesis at depth due to compaction and temperature increase with depth, resulting in increased precipitation of cements.

RFT data (Appendix) show that many units in A08Z, A32 and A40 are not in pressure communication. Faulting does not always have a detrimental effect on rock quality; well A29 penetrating the fault is high quality and not compartmentalised, based on sustained oil rate and pressure communication between sandbodies indicated by RFT data.

4.3.5 Producing Units

The sandstones which were the best oil producers throughout fip3 are LNG, UNA, UNE, UNG and the Tarbert Formation. These are commonly shown to be producing by PLT data (Appendix). These are fluvial channels or tidal shoal, high permeability and are the first to be swept, but only where they are connected to an injection well. Fluvial channel type B sandstones dominate flow and are the highest permeability facies association. Although the Broom Formation is often of good reservoir quality, it is commonly below the OWC in fip3 so does not produce oil.

The UNA and Tarbert Formation are both tidal shoal with a sheet sandstone geometry. The sheet sandstones have a significant degree of lateral connectivity. This is supported by RFT data where these sandstones are similarly depleted throughout, indicating pressure communication in these sandbodies between wells. Furthermore, PLT data indicates that injection water travelled through these units. Injection water swept these sheet sandstones and in places, have been proven to travel into units above and below them (for example UNA sometimes produced with UNB and produced in all wells except A37).

LNG (fluvial channel type B) is a high porosity unit but the adjacent LNF and Mid Ness Shale tend to be impermeable. LNG is a good flow unit, however, is not indicated to be stratigraphically connected between wells.

UNE and UNG are fluvial channel A/B and high porosity. UNF often produces in conjunction with UNG. UNE is fluvial channel or fluvial floodplain mud rocks with crevasse splay sandbodies. UNE-G produce together in A29 and A48. Where rock quality is reduced or the unit is thinned, oil production is reduced.

LNE and UNC have a mid-level of production. LNE often produces with LNF and produces in wells to the north of fip3 (A03Z, A15, A16, A21, A37 and A48) where it is thickest. It is a fluvial channel A/ B, except in A08Z and A40 where it is a lower permeability bayhead delta sandstone and doesn’t produce. UNC produces on its own. It is fluvial channel A/B and tidal shoal in A08Z.

Crevasse splay sandbodies in the Upper Ness Member did not produce much oil. These are thin with average permeability and porosity, however, are typically located within impermeable fluvial floodplain mud rocks, so may be isolated from injection water. Crevasse-splay deposits form a volumetrically significant component of many fluvial overbank successions. Large deposits can be up to 2km wide (Mjøs 1993). The sandbody size vs well spacing (between 0.5 and 1km in fip3) means that the crevasse splays would likely be connected between many fip3 wells and therefore if a producer/ injector pair had been drilled into a crevasse splay sandbody then it would be flooded. LNA only produces in A08Z, A40 and A48, in conjunction with LNA-E, however in these wells LNA has no porosity or permeability and is a bay margin shale. LNC is bayhead delta or fluvial channel and doesn't produce by itself.

4.3.6 Connectivity and Depletion

This study has compared the RFT data (Appendix) of wells in close proximity and either side of faults to indicate which wells and sandstones may be in pressure communication.

A40 and A14 are interpreted to be in different compartments because they are differentially depleted, where A40 is at lower pressures than A14.

There is no clear pressure communication between A40 and A32 either side of the OWC at the south of fip3. A32 and A40 both show similarly low pressures for the Tarbert Formation (2175.7psi and 1779.7psi respectively). A40 has significantly lower pressures for LNG, UNA, UNC and UNG than A32. A40 also has lower pressures than A14 in the Broom and Etive Formations, although with a smaller (~1000psi) difference.

RFT data indicate that A37 (in the eastern fault block of fip3) may be in pressure communication with A32 and that the fault may not be sealing. Similar pressures were recorded in the Broom, Etive and Tarbert formations. There are small pressure differences between the wells in UNA (5848psi and 4558psi respectively) and UNC (4417psi and 5733psi). In UNG, A37 (3603psi) is at much lower pressures than A32 (6023psi). There is not enough evidence to conclude certain pressure communication, however the waterfront has been tentatively inferred in chapter 4.1.9 to travel from the main sector of fip3 to the eastern block, indicating A37 is not isolated. There is little pressure communication indicated between A37 and A21 meaning that the north fault may be sealing.

RFT data show that A21 is at low pressure, indicating many of the sandbodies have been depleted. A21 and A29 appear to be in pressure communication in the Ness Formation (except in LNE). The Broom and Tarbert Formations are not in pressure communication. When comparing A21 RFT data to A16 and A32 little pressure communication is indicated over the fault separating the NE block, as A21 is much more depleted. A16 and A32 show similar pressures in the Broom, Etive, UNC and UNG.

RFT data do not support a stratigraphically well connected reservoir model. RFT data indicates that fip3 is highly compartmentalised as there is little pressure communication indicated in sandbodies between wells and above and below sandbodies. Most compartmentalisation is indicated to the more deeply buried west of fip3 and within the Ness Formation due to it being highly heterogeneous. However, RFT depletion behaviour show that many sandstones are connected between wells.

4.3.7 Potential in fip3

Compartmentalization in fip3 is present due to laterally persistent mudstones, faulting, cementation and variable dimensions of channels. Although fluvial channels in the Ness Formation are the most permeable sandbodies in fip3, they have high permeability contrasts and very poor connectivity between wells. They are thin and often isolated, despite stacking in some areas and are rapidly drained, responsible for the initially high yet quickly depleting oil rates. Due to the lack of connectivity there is likely still oil remaining in isolated channel sandbodies, particularly in compartmentalised or underdeveloped regions of fip3.

Contrastingly, laterally extensive sandstones across fip3 such as tidal shoal (Broom Formation and UNA) and distributary channel (Etive Formation) are connected between wells would be have been flooded when they were drilled by the injector/ producer pairs in fip3. These sandbodies were water saturated and pressure depleted in later wells, evidence that these sandbodies have been flooded. Similarly, the wide lateral extents of crevasse splay sandbodies (of the Upper Ness Member) in fip3 mean that if a producer/ injector pair had been drilled into a crevasse splay sandbody then it would be flooded.

An increase in WOR due to increased water injection often results in the cessation of production. However, massively increasing water injection can result in an increase in oil rate and a decrease in WOR as water starts to travel through the less swept adjacent lower permeability horizons and picking up previously bypassed oil as the flood front spreads out (Gluyas et al, 2010). This tactic could have the potential to be useful in fip3.

A29, A32, A37, A40, A48 all reached 20 WOR and 95% water cut so are considered to be swept of oil. Early wells near producers such as A03Z and wells converted to injectors (A08Z, A16 and A21) will also have had the oil expelled or swept. Therefore, the NE and middle of fip3 are likely mostly depleted of oil, however there may be potential to the south and the west.

Wells with initially high oil rates were typically the early wells, or wells with water injection pressure support. Where later wells (A32, A40 and A41Z) were drilled into existing flood fronts the permeable layers were already water saturated, as the oil had already been swept, the oil production was lower (with the exception of A41Z). However, wells drilled into the flood front did receive good pressure support.

A41Z performed very well for a late well in a partially swept area of the NE block. Oil rate was still high and the WOR was just 2.71 when production was shut off, indicating that that there may be remaining oil in the NE block. Although A41Z was on the sweep path of water injector A21 production ceased simultaneous to water injection at the end of the field's production, so the remaining oil would not have been swept at a later date.

A15 (with the exception of A21 which was converted to a water injector) is the only other well aside from A41Z that did not reach 95% water cut in the north eastern block. A15 reached a WOR of 6.5, but as it ceased production in January 1989 and was on A21's water injection path the oil would have likely been swept to A41Z and A29 by the water front. There is no evidence for this in the oil rates of A41Z and A29 as A41Z because production began in May 1991 (2 years and 4 months after A15 was shut off). Although the oil rate of A29 had a minor increase in May 1989 (Figure 77), this was before the water breakthrough was interpreted in September 1991, so is unlikely to be caused by oil being swept from A15. RFT data, CPI data and sustained oil rate indicate that the connected rock volume to A15 was not very compartmentalised so there is unlikely any isolated sandbodies with oil remaining.

There may be oil remaining in the undrilled section of the NE block between A21, A29 and A48. The NE block has good rock quality, high net sandstone thickness and is not very compartmentalised compared to the rest of fip3, and A41Z indicates that there is remaining oil and the potential for well producing wells to exist in the sector.

Although A32 and A40 reached 95% water cut they are in compartmentalised areas (evidenced by their rapidly draining oil rate, CPI log and RFT data indicating that the sandstones are not in pressure communication) so there may be oil bearing isolated sandbodies, particularly in the poorly connected, fluvial channels of the Ness Formation. This is the case in other compartmentalised areas of fip3, particularly to the more deeply buried west of the field, that have reached 95% water cut having potential in isolated or lower permeability sandbodies.

A37 in the eastern block of fip3 reached 95% water cut and is also indicated to have a highly compartmentalised connected rock volume. It likely reached a 95% water cut despite having a low cumulative oil production due to being extremely compartmentalised, the oil was drained rapidly, however there is likely oil remaining in the compartmentalised rock volume of the eastern sector. A perched aquifer has been indicated in the eastern sector meaning that the Tarbert Formation may be water saturated and therefore not oil bearing in the entire eastern fault block.

The south of fip3 is a very undeveloped region, with just A14 drilled. A14 received good pressure support, had a very steady oil production over a long period of time and did not reach 95% water cut, indicating that the connected rock volume was not very compartmentalised and there is still remaining oil in the area. The CPI log indicates that the rock is of good quality with high porosity sandstones, particularly the Etive which thickens to the south. There is therefore indicated to be potential for redevelopment in the south of fip3 by A14's good performance, pressure support and good rock quality.

5 Conclusions

Controls on the production performance of wells in fip3 were timing (where earlier wells generally produced more oil due to higher pressures, oil not yet being swept and a lack of operational issues), rock quality (a function of burial depth and facies), compartmentalisation and connectivity of sandbodies (a function of faulting and depositional environment), pressure support, well spacing and operational issues.

Wells in fip3 had an initially high oil rate, which rapidly declined as pressure was quickly depleted. This is attributed to complex compartmentalisation and the high permeability, but thin and poorly connected, fluvial channel sandbodies in the Upper and Lower Ness Members being quickly drained.

Stratigraphy was a strong control on the dynamic behaviour of the field and data does not support a stratigraphically well connected reservoir model. The paralic delta environment has produced a highly layered reservoir involving laterally persistent mudstones and variable dimensions of channels and valley fills, resulting in a high degree of compartmentalisation. Cementation, particularly in the deeper buried west of fip3, and faulting has further compartmentalised the field.

Fluvial channels are the highest permeability facies association, dominate flow, and were the first to be swept, but only where they were connected to an injection well. Due to their lack of connectivity there will likely be oil remaining in isolated or poorly connected fluvial channel sandbodies, particularly in compartmentalised or undeveloped regions of fip3 (such as the south). Fluvial channels are most common in the Ness Formation, a particularly compartmentalised interval where laterally extensive and sheet like architectures are rare.

The distributary channel facies association of the Etive Formation is stratigraphically connected between wells and has been flooded and the oil swept. Similarly, sheet sand geometries such as tidal shoal and crevasse splays have a significant degree of lateral connectivity between wells in fip3, and when drilled by an injector/ producer pair they were flooded.

The best producing wells in NW Hutton were early wells with good pressure support, drilled into the shallow crest, however A14 to the south was drilled deeper and was highly productive with clear pressure assistance and an effective flood front. Many wells had low productivity due to being drilled into existing flood fronts (common in later wells such as A41Z and A48) or stealing production from existing wells (A32 from A08Z). Additionally, shut in of many wells in fip3 were attributed to operational issues and some wells had not reached 95% water cut and were still producing when shut in occurred.

The water injection programme implemented focused to the middle and north of fip3 (although the flood front from A21 reached A14 to the south of fip3) and 3 production wells were converted to water injectors. Injection water has been indicated to travel long distances through the Upper and Lower Ness sand prone channels, particularly of tidal shoal facies association. Wells drilled into the flood front received good pressure support despite permeable horizons being previously flooded. Injected water bypassed significant volumes of oil in lower and higher permeability units that are poorly connected or isolated from the sandstones into which the water was injected. This results in rapid water breakthrough occurring in well interconnected high permeability sandstones, commonly of sheet geometry in the Etive, LNG and UNA intervals, observed in rapid WOR increases.

The production wells located to the NE and middle of fip3 reached 20 WOR and have had oil expelled from the higher permeability sandbodies connected to the injector/ producer pair, however there may be oil remaining in lower permeability sandbodies. Dramatically increasing the WOR could sweep adjacent lower permeability horizons and pick up previously bypassed oil.

This study has indicated potential for redevelopment in the undeveloped south of fip3 by A14's good performance, pressure support and good rock quality.

6 Future Work

In the future, investigating the following may prove important in order to further understand the dynamic behaviour of the reservoir to predict its future performance under various development and production strategies:

a. Undertake static modelling. Integrated reservoir modelling would be a valuable technical approach for estimating oil/gas reserves more accurately, simulating future production profiles and reducing the uncertainty associated with the static and dynamic reservoir descriptions. Localised and more detailed sedimentary modelling, particularly of the Ness Formation, is required to predict reservoir geometries.

b. Undertake detailed flow simulation. This would allow further exploration of flow connectivity and fluid movements across channel fill and associated facies. Paired with more detailed fault mapping, this would enable further understanding of the effect of the water injectors and fluid pathways in fip3, and fluid flow in compartmentalised, paralic reservoirs.

c. Compare and contrast to other paralic sequences that are major hydrocarbon provenances. Examples may include the Niger or Nile deltas. This would allow better understanding of the controls on hydrocarbon reserves in paralic delta settings at both a pore and regional scale.

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Appendix

Appendix Contents

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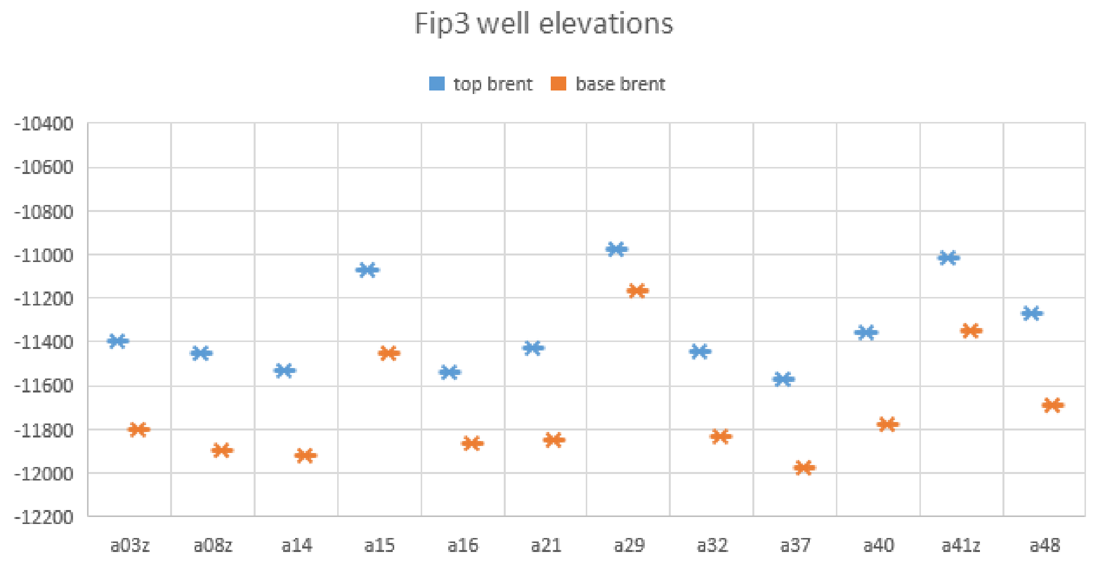
i) Well Elevations



Well elevations in fip3 (ft TVDSS)

ii) Geological Descriptions of Each Well

A03Z

Tarbert: Fine-medium sandstone, moderately well sorted with siliceous cement and good porosity, very good on CPI

Upper Ness: Sands are fine, also medium sandstones with good porosity, well sorted and a weak siliceous cement to the base. They are relatively thin compared to the Upper Ness sands in fip3. UNB is a sand (not shale), UND and UNF are shale, cemented so no porosity or vertical permeability. Above UNG is siltstone grading to very fine sandstone with shale and coal, fine sand is thin but has moderate porosity.

Lower Ness: sands are fine to medium, moderately sorted with moderate porosity, siliceous, locally hard and calcareous with good CPI porosity. LNG and LNE sands have particularly good porosity and permeability. There is a thin cement layer between LNF and LNG which reduces vertical permeability. LNA-C is comprised of mud rocks and thin fine sand and is a poor-quality reservoir with no porosity or permeability.

Etive: thick and fine to coarse, clear sandstone, moderately sorted, moderate porosity siliceous, locally hard and calcareous.

Rannoch: thin layers of cement, very poor perm, moderate porosity, fine to medium sand grading to siltstone at base with no porosity.

Broom: medium to coarse, fining up to fine sand at top and calcareous cement.

A08Z

Highly cemented, appears very vertically compartmentalised, sands are very thin, vertical permeability not very good, lots of thin poorer quality layers (except Tarbert)

ODT 16020ft meaning Broom is water saturated

Except Broom all layers >95% oil saturated (as early well, unswept)

High N:G as Brent very thick, although very compartmentalised

Tarbert is very thick, very good quality, a fine to very coarse sand, sub angular to sub rounded, poor sorting and locally calcareous, with one thin cemented bed in the middle. Very good porosity filled with H/C and excellent permeability

Upper coal series (upper UN) is a dark grey claystone, very thick, firm, silty with pyrite traces

UND-UNG sands are thin, very poor vertical perm, very fine sandstone, silty in part, well sorted with a siliceous cement. Geology reflects poor production from these units

UNA-UNC sands are thicker, fine grained, sub angular to sub rounded, well sorted, also with siliceous cement. Geology reflects better production, especially UNA

Thin claystone and coal and cement layers compartmentalise the UN and reduce perm

The MNS is claystone and thick

LN sands are medium sandstone, sub rounded, well sorted with siliceous cement at the top (LNG), in coarsening up packages LNE is fine to coarse, fining down sub angular to sub rounded, fair sorting, moderately hard with siliceous cement, going down to very fine to fine well sorted sands at the bottom (LNA). The sands are separated by thin and thick dark grey claystone, cements so that little of the LN has good hydrocarbon filled porosity, and poor perm, although better LNE-LNG. PLT indicates LNA-D may be producing together, CPI looks v compartmentalised

Etive producing and very thick, but poor quality- some hydrocarbon filled good porosity to the top and bottom. It is fine, also coarse sand, coarsening up, sub rounded to rounded, well sorted with a siliceous cement. Thinner sand layers reduce perm and poros between coarser sand.

Rannoch not producing- very cemented, very poor porosity and perm, v little indicated hydrocarbon. It is a very fine, sub angular, well sorted, calcareous and siliceous cement, with dark brown, hard, blocky, micaceous sandstone to the bottom.

Broom not producing- v little h/c indicated, water saturated. Ok porosity- it is predominantly loose quartz grains, fine- coarse, sub angular to sub rounded and no visible cement. Also with dark grey micro micaceous siltstone.

A14

UNA-G, LNC-G have good porosity filled with hydrocarbons. There is not much cementation. The shale layers are very thin but still reduce vertical permeability.

Above UNG is laminated siltstone and shale with beds of coal and tight, well cemented sandstone. This didn’t produce.

UNA-G produced well, it is medium grained well sorted sandstone with a high visible porosity, with finely laminated siltstone beds containing flaser added shales in part. UNE-G has good perm and porosity, UNF is very thin (so UNE and UNG sands are flowing as one), and sands are coarse with good hydrocarbon filled porosity. UND is only CPI interpreted shale. UNA is fine grained well cemented (silica) sandstone.

The Lower Ness fines upwards and is fine well cemented (siliceous and kaolonitic) sandstone with argillaceous siltstone beds and claystone interbedded with sand LNA and LNB. The sands are every thick with high porosity and permeability within, especially LNG, which produced the most.

The Etive is thick and loose medium, sometimes coarse sandstone.

The Rannoch is sandstone, increasing in argillaceous and silt content, and is claystone at the base. It is cemented in layers, reducing vertical permeability to almost 0.

The Broom fine-medium to coarse sandstone is also well cemented giving it a low porosity and permeability, it is also water saturated.

Facies interpretation: The Etive distributary channel is very thick here. UNA tidal shoal. UNB (finer) sand (not silty bay margin). Less bay muds with fluvial channels in UN.

A15

Oil saturated. Lack of cementation and poorer porosity and perm beds, so good vertical por and perm- RFT shows LN and Etive in pressure communication.

Tarbert is very fine to fine sand.

Above UNG is laminated dark grey shale with laminations of siltstone with micaceous shaley partings, shale, laminated coal and hard fine sandstone. There is very poor permeability and porosity here. The facies are interpreted as fluvial floodplain mudrocks with (cemented/tight) crevasse splay sandstones and alternating bay margins and bay margin heterolithics.

UNA-G is fine, grain supported sandstone with poor to moderate at the top, moderate lower with occasional black carbonaceous laminations, siliceous cement and occasional quartz overgrowths. There are thin silt and biotite rich, very silty mud beds. UNA is interpreted as a tidal shoal, UNB a bay margin, UNC-E alternating A and B multi-storey fluvial channels. UNF-G is bay mud to alternating bay margin and bay head delta and sandstone gets finer, with poorer porosity.

MNS is interpreted as alternating bay margin and bay margin heterolithic

The Lower Ness comprises of medium sandstone coarsening upwards, moderately sorted, rarely carbonaceous, grain supported with excellent porosity and permeability at the top. These are interpereted as multi-storey fluvial channels (types A and B, differentiated in grain size and Vclay content). LNF has finer grains and worse porosity and perm, and is interpreted as bayhead delta and bay margin heterolithic. The shale layers are silty, dark grey, as well as light grey laminated siltstone layers, interpereted as alternating bay margin heterolithic and fluvial floodplain mudrocks.

The Etive consists of medium grained, angular sandstone inn a loose silica cement with mica in groundmass and micaceous partings. This, and LNA is interpreted as a distributary channel.

The Rannoch is finer calcareous sandstone with coal beds, sporadic and woody, interpreted as the offshore transition zone grading into the lower then middle shore face upwards.

The Broom is micaceous, coarse sandstone with excellent- moderate visible porosity and permeability, and is interpreted as a tidal shoal.

A16

Tarbert/UN (I think UN): The sands are good quality, good poros filled with hydrocarbon and upper fine to coarse sandstone with rare coarse, loose sand, vitreous quartz, sub angular to sub rounded, moderate sphericy. UNA, UNE thick. There are beds of cement and medium grey claystone, silty with trace coal

The MNS is claystone grading to siltstone and occasional fine sand

LNG is very thick and excellent quality, with oil stained soft sand, non-calcareous. Thin coal beds compartmentalise the LN, also cement and the claystone grading siltstone, light to medium brown, soft to firm, blocky and laminated. Below UNE is mostly clay and fine sand and no porosity, perm or indicated hydrocarbon

The Etive produces despite low amount of hydrocarbon filled porosity. It is a medium to coarse sand (cemented in middle so no poros or perm) with loose quartz, sub angular to sub rounded, fair sphericy, fairly sorted, finer grained with depth.

The Rannoch includes limestone white blocky granular micritic interbedded with sand and clay. Rannoch low quality poor perm due to lots of thin cement layers and clay. Does not produce.

The Broom produces only water and is soft-firm blocky, laminated non calcareous, carbonaceous sand with predominantly loose, fine –coarse quartz, very coarse with depth, poorly sorted, sub rounded to sub angular. Indicated porosity and perm is ok, but below OWC so water saturated and no hydrocarbon.

Ok quality geology, but Brent thin.

A21

Broom is mostly water saturated (below OWC), Rannoch 30-50% water saturated, Tarbert 20% water saturated, Ness and Etive 100% oil saturated. Area mostly unswept.

UN sands are thick, with good porosity and vertical perm and indicated hydrocarbons in the coarser areas (parts of UNA, UNC, UNE, UNG). The sand is fine to medium at the bottom coarsening up to fine to medium good sphericy, moderately well (siliceous) cemented, moderately well sorted with moderate to good porosity. Claystone layers are very thin and a medium grey brown, firm, blocky, locally carbonaceous and non-calcareous.

The MNS is thin ~30ft, claystone, locally carbonaceous with occasional thin sand streaks.

LNG and LNE are thick and quartz arenite, friable to moderately well cemented, medium grained, sub angular with moderate to good sphericy, unimodal, clean, homogenous well sorted, grain supported with silicic cement and moderate porosity. LNG and E have excellent vertical perm.

More claystone to the bottom of LN, commonly interbedded with and grading to silty, non-calcareous mudstone with shale and coal layers meaning LNA-LNC are very poor quality and not producing.

The Etive IS V THIN. Etive/ top Rannoch producing. The only well where Rannoch produces, here it is fine sand (fining down), well sorted, micaceous, locally slightly calcareous, sub angular, good sphericy fining to medium grey brown mudstone. Thin cemented layers throughout.

Broom does not produce, below OWC so water saturated. It is fine- medium to coarse sand, sub angular with poor to moderate sphericy, poorly sorted, with locally calcareous laminated doggers. Porosity is ok. Fines up.

A29

LNC-Tarbert is all very good quality rock with excellent vertical porosity and permeability, thick sand bodies, lack of cementation.
LNF is interbedded sand and shale, with poor porosity, no indicated. Hydrocarbon, no vertical permeability. LNE and LNG are especially thick.
Top UN not as shaley as other wells, thick sand with excellent porosity at top- mostly sand and produces a little on PLT.
Shale layers in UN are thin with no hydrocarbon, no porosity or permeability

A32

Lower Rannoch and Broom water saturated (below OWC).

UNA 20-25% water saturated

Etive 20-30% water saturated

Tarbert is a coarsening up light grey soft sandstone that is water saturated at the bottom and the lower half has poor permeability. It has good hydrocarbon filled porosity where not water saturated.

The shaley upper UN is thin, with no porosity or perm

The sand in the UN is very fine to medium grained, sub angular to sub rounded, poorly-moderately well sorted, loose, with moderate sphericy

Upper UNE, UNF and lower UNG are low quality grey brown siltstone, carbonaceous grading to siltstone with coal horizons with very poor vertical perm and porosity, cemented in layers and no good porosity filled with hydrocarbon

UNA is very good quality and UNG is thick- best producers

LNG very thick, good perm but doesn't produce

LN is generally low quality, shaley layers are thick, sands are thin with very poor permeability

The Etive has ok porosity but vertical permeability is poor (despite RFT indicating it is not compartmentalised), it is medium to coarse sandstone with moderate to high sphericy and moderate visible porosity

The Rannoch has cement layers with no porosity or permeability and the Broom is sandstone with clay interbeds and no hydrocarbon filled porosity (as water saturated)

A37

LN is poor quality. Very poor vertical perm, poor porosity. Sands very thin and fine, with shaley layers within. Very fine to fine sandstone, occasionally medium, moderate to well sorted, thinly cemented, poor to medium visible porosity, commonly micaceous with claystone and argillaceous sand interbeds.

Shale layers lnb, lnd, lnf very thick with 0 porosity- vertically compartmentalising field. Also thin layers of cementation and coal. UNE-E is fine to medium sandstone, above which is silty, non-calcareous claystone with thin sand beds- compartmentalisation, sands not connected

Tarbert very good quality but water saturated

A40

Tarbert very good, produces well. 90-100% oil saturated, excellent porosity and vertical permeability, the sandstone is very fine to coarse, poorly sorted with an occasional kaolinite matrix

UN is good quality. UNG very thick and good quality but somewhat water saturated. Unit compartmentalised by claystone with no porosity or perm. Upper UN is dark grey claystone occasionally grading to siltstone. The sandstone is kaolonitic, carbonaceous, occasionally very fine, sub angular quartz grains. UNA has the most production- is good quality but thin and oil saturated. Dark grey claystone, light grey siltstone and coal present in thin layers. Shale layers very thin.

LN is poor quality, very little H/C filled pore space due to fine, occasionally medium sandstone which is kaolinitic and carbonaceous, angular to sub angular, thin siltstone and coal layers with no porosity reducing vertical permeability, very compartmentalised. Thin cement.

Etive is very thin, very fine to medium sandstone (usually better) with very little hydrocarbon filled pore space

The Rannoch is thin and very poor quality- very cemented and mostly siltstone with argillaceous matrix, non-calcareous.

Broom water saturated due to higher OWC in south. Rannoch ~50-100% water saturated, Etive 25-100% water saturated. Some units in Ness completely water saturated (sand units, top UNG).

A41Z

Oil saturation higher than A48, lower than nearby earlier wells A15, A29 as later and some oil been swept

Most water saturated layers are UNE, LND-G

The Tarbert is thin, but good quality and produces. It is fine to medium sandstone (coarsest in the middle with the best porosity and perm), sub angular and sub rounded. It has good porosity filled with hydrocarbon and has ~5% water saturation, so likely not in an area already swept by A21

The UN sand is fine to occasionally medium, moderately sorted, sub angular to sub rounded and non-calcareous.

UNE produces and is thick, water saturated at the bottom, good poros, only the bottom water saturated bit has good permeability and hydrocarbon indicated

Lots of thin cement layers- but RFT suggests these are not compartmentalising

UND produces but is pale brown claystone, fine-medium grained with moderate sorting and no visible porosity. No perm indicated by CPI

UNA is very thin (~10ft), but very good quality, ~20% water saturated, but good poros and perm and is producing

The LN is excellent quality with no shale layers (except LNA, LNB), good porosity filled with hydrocarbon, good permeability, but is 20-30% water saturated with some layers (in LNE and LNG) 100% water saturated (oil already been swept by A21), however no production came from the LN despite being perforated- LNG usually good producer but water saturated

Etive very good quality, fine sandstone, moderately sorted, sub angular to sub rounded with a weak silica cement, was perforated but no production

The Rannoch does not produce and is very poor quality- claystone, moderately hard, micro micaceous, silty grading to siltstone with medium sandstone in thin bands at the bottom and is cemented at the top, giving no porosity or permeability. Not perforated, no production

Broom is perforated, but doesn’t produce and is ok quality sand, cemented in middle

A48

Low LN is bad (0 por and perm), otherwise ok, not too vertically compartmentalised, high N:G. Resistivity and density logs shows lots of good porosity rock filled with hydrocarbon.

A48 has a high water saturation, low oil saturation, especially in UNA and LNG, which are usually the layers that produce best. Tarbert and UNG have the higher oil saturations (70-90%), these layers produced well on PLT

iii) PLT Data

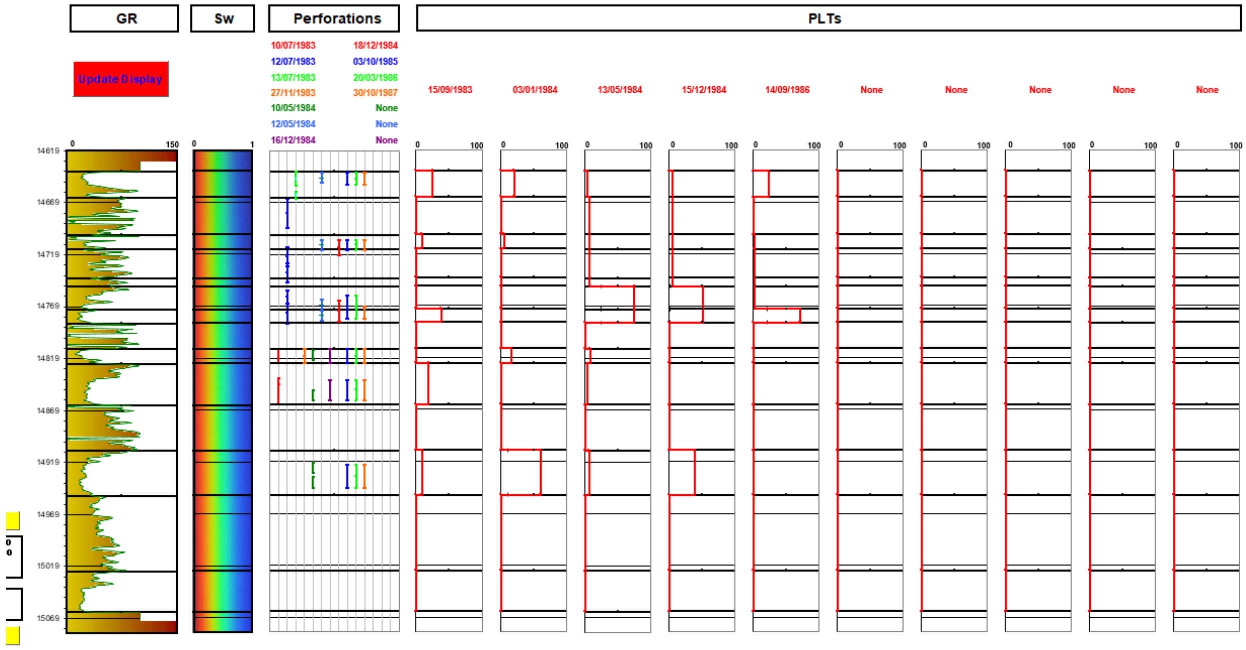


Figure iii)a - A03Z PLT

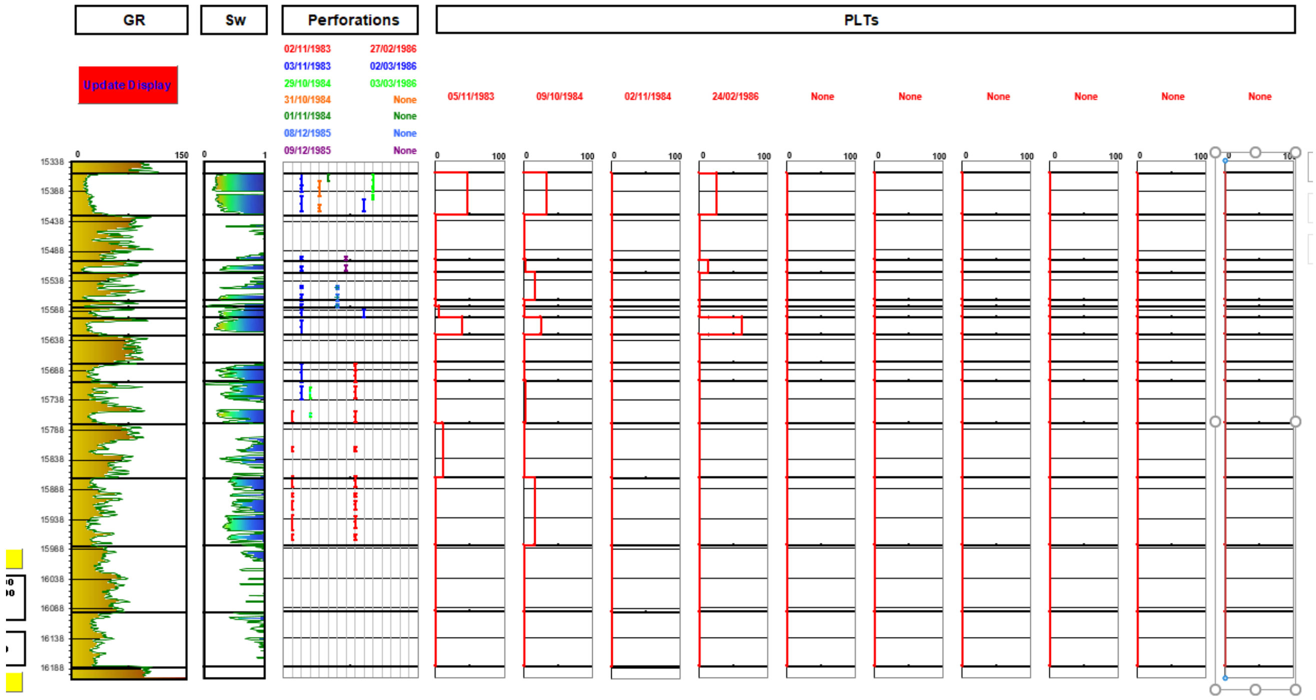


Figure iii)b- A08Z PLT

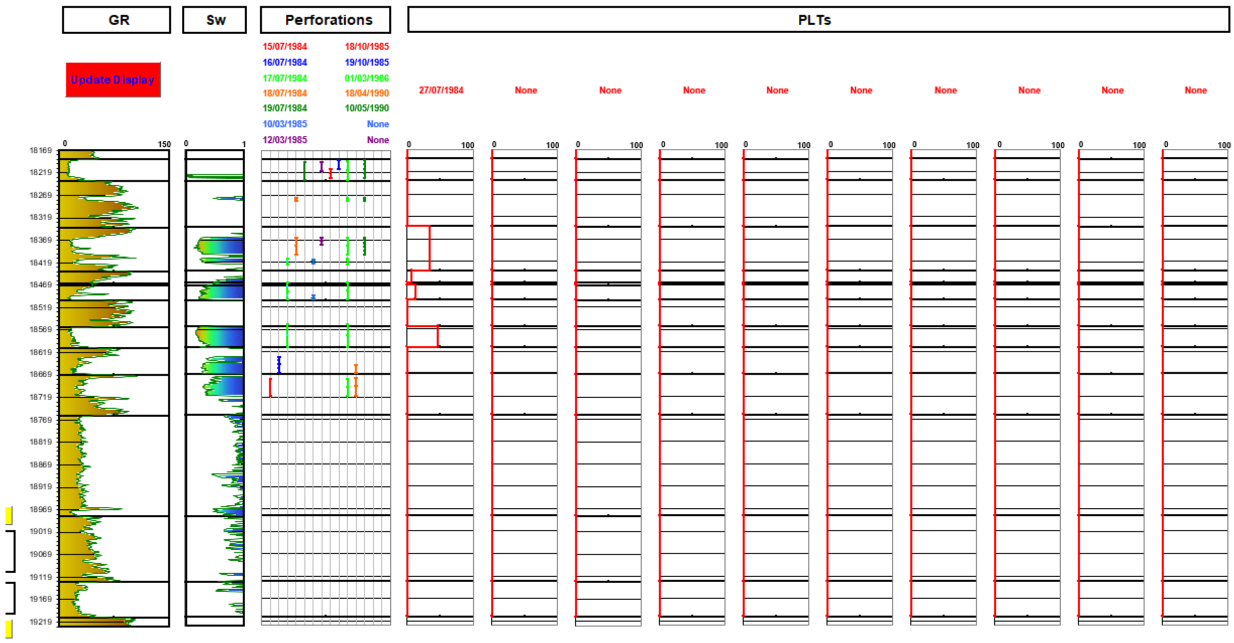


Figure iii)c - A14 PLT

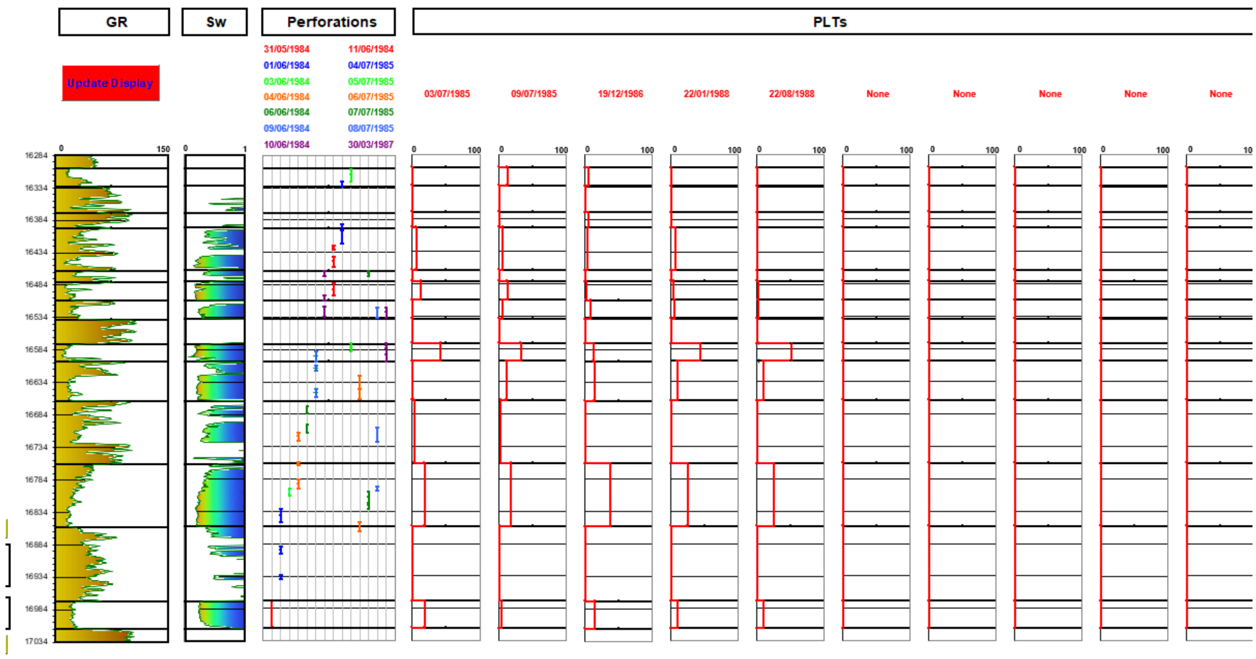


Figure iii)d - A15 PLT

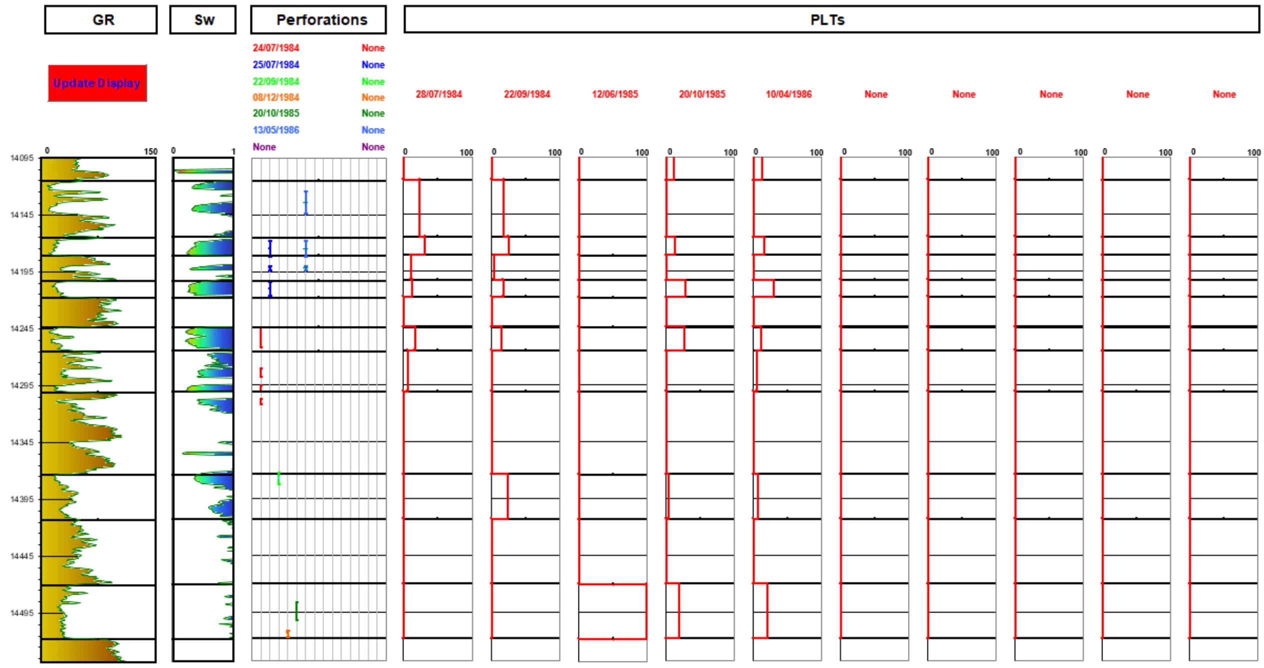


Figure iii)e - A16 PLT

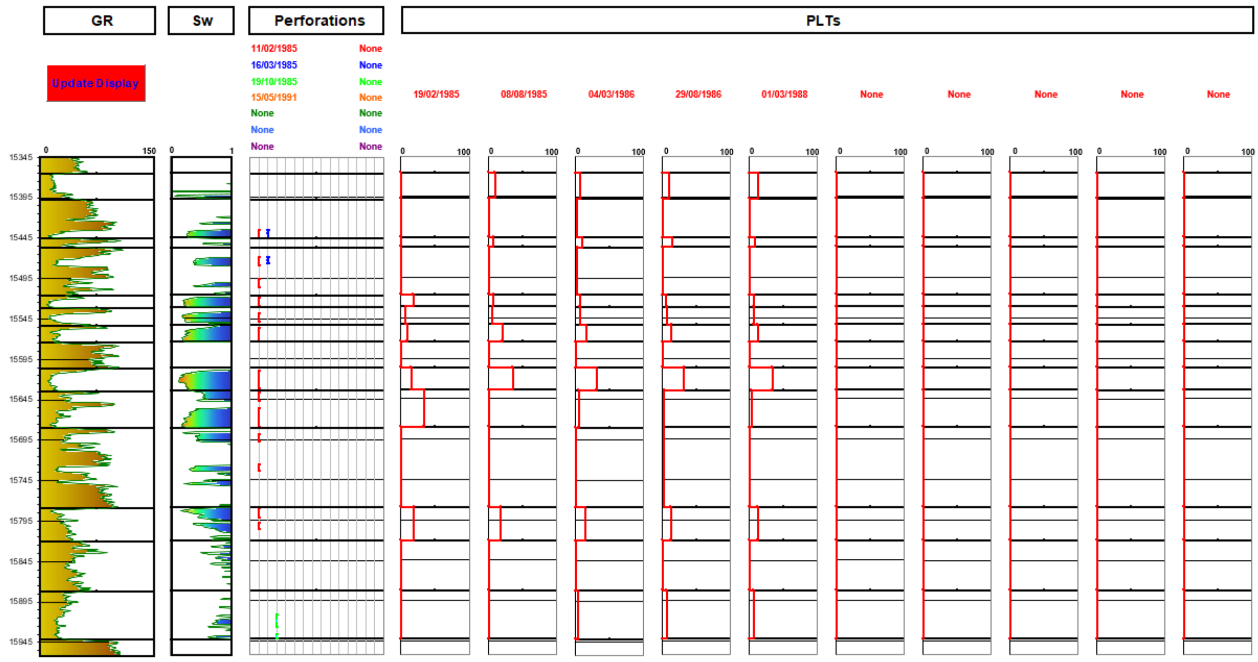


Figure iii)f - A21 PLT

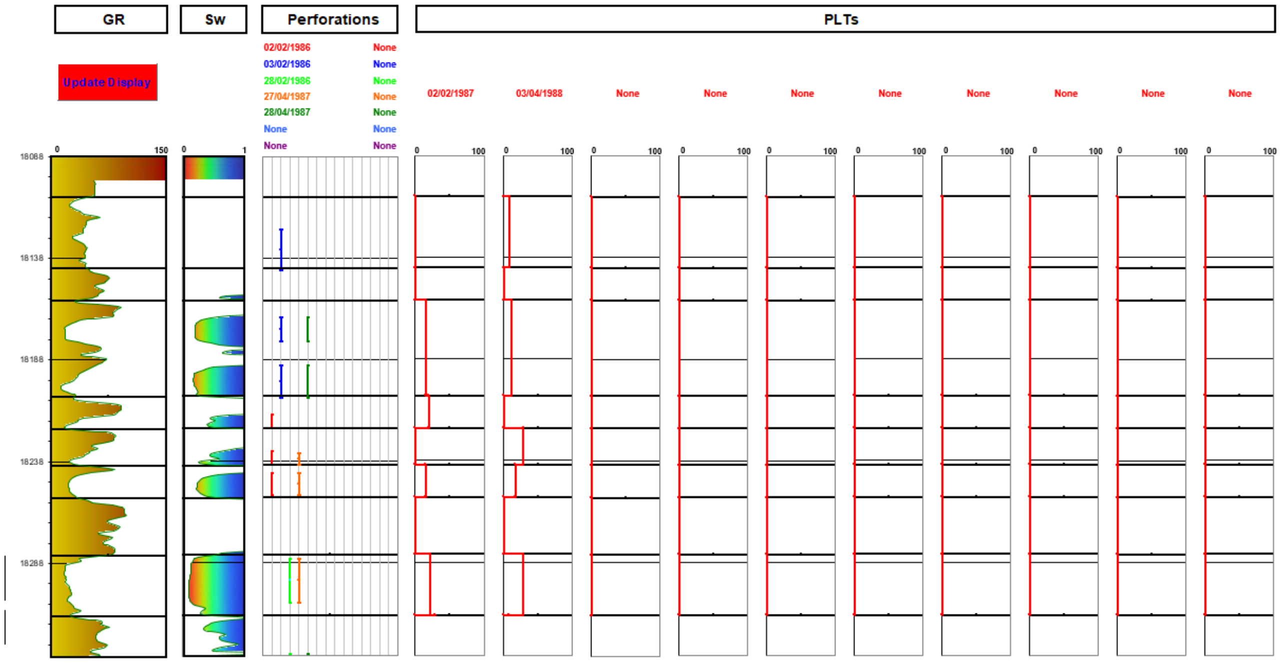


Figure iii)g - A29 PLT

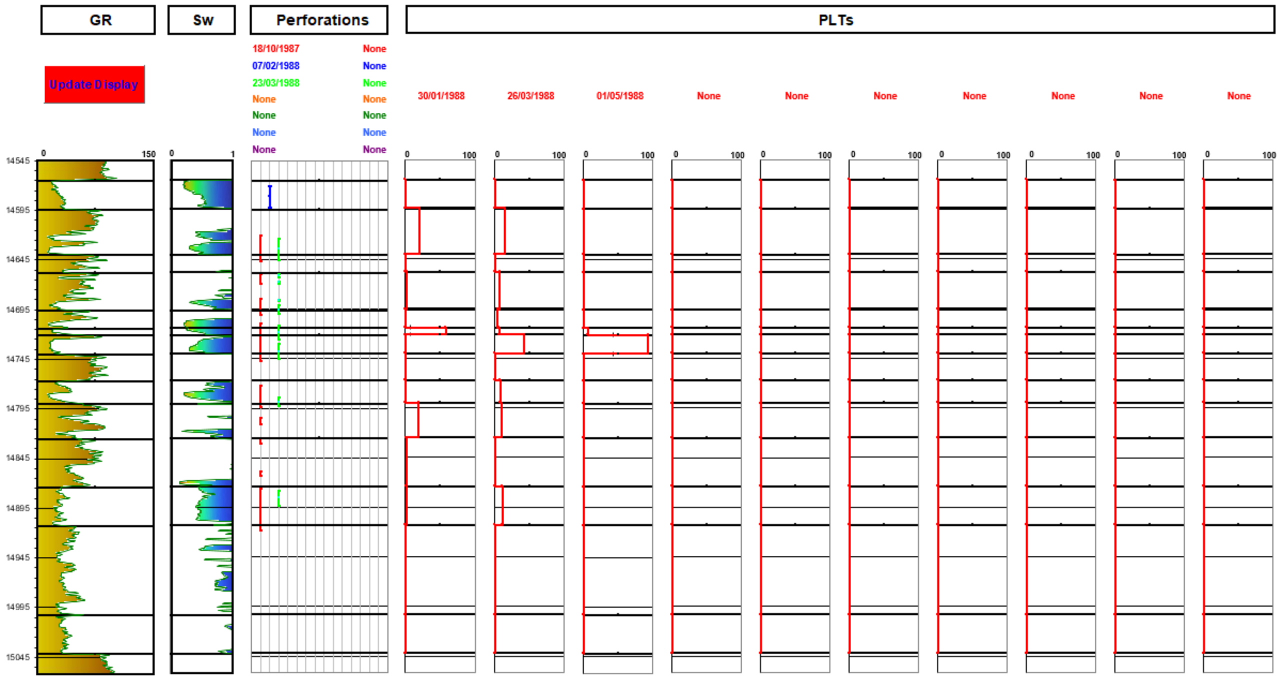


Figure iii)h - A32 PLT

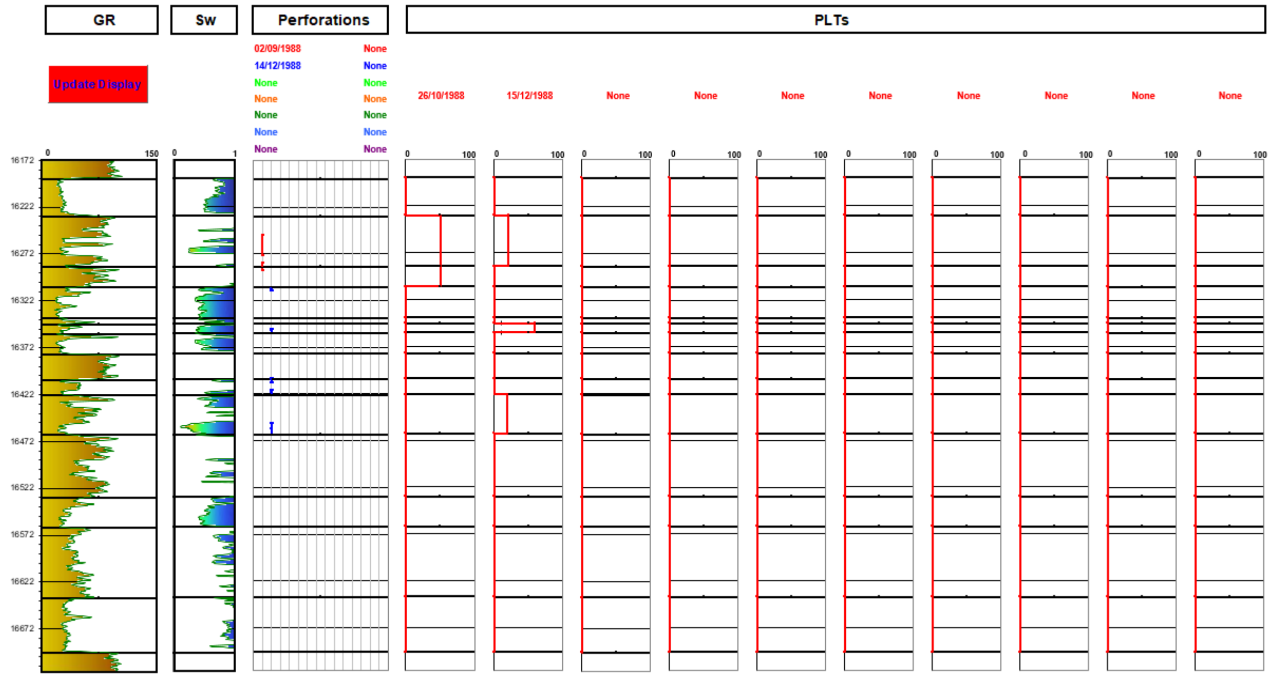


Figure iii)i - A37 PLT

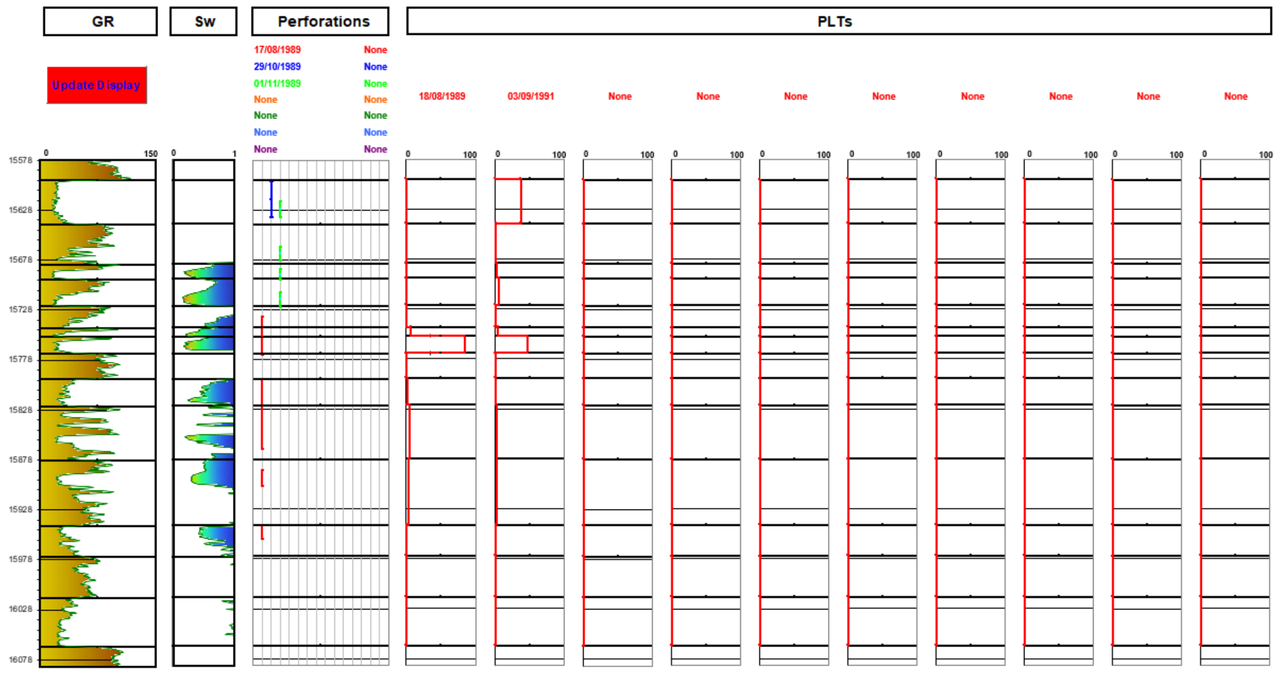


Figure iii)j - A40 PLT

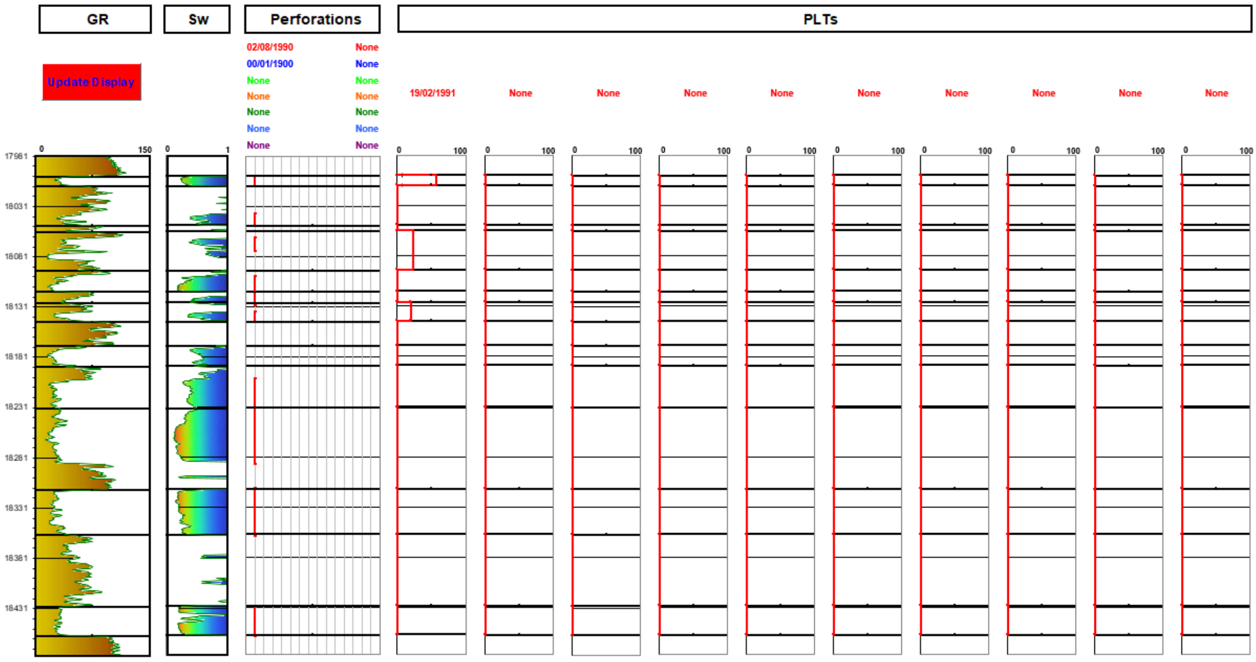


Figure iii)k - A41Z PLT

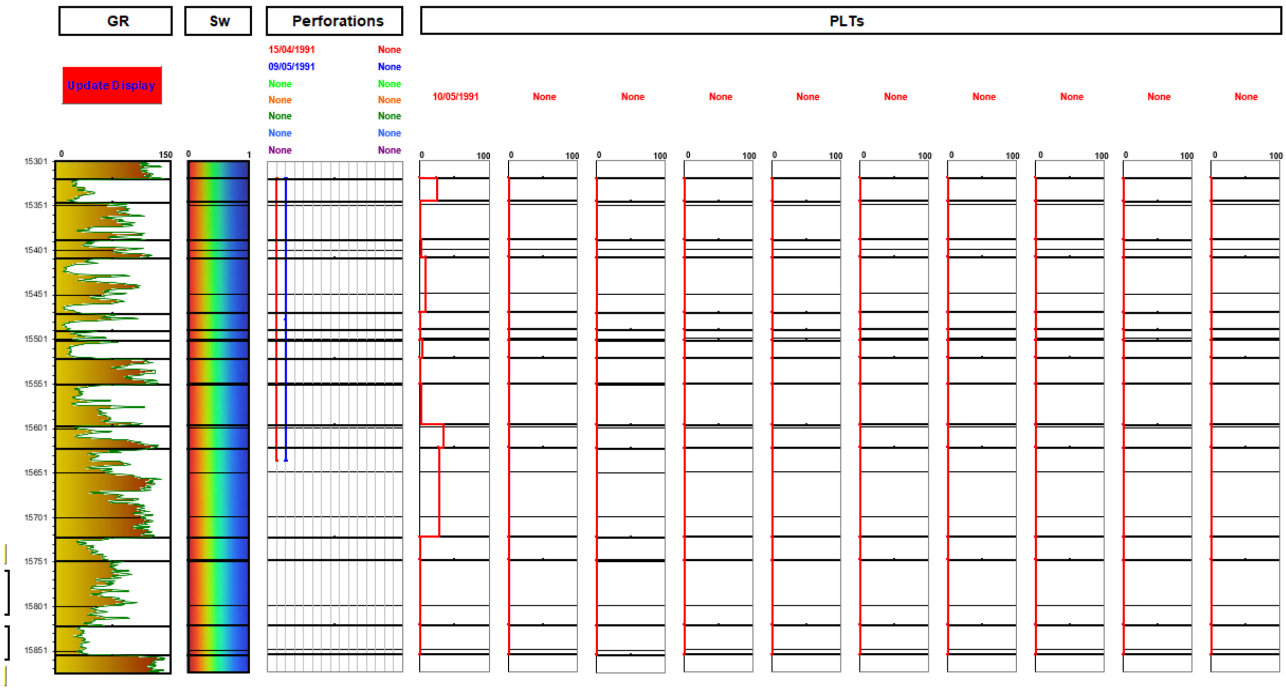


Figure iii)l - A48 PLT

iv) RFT Data

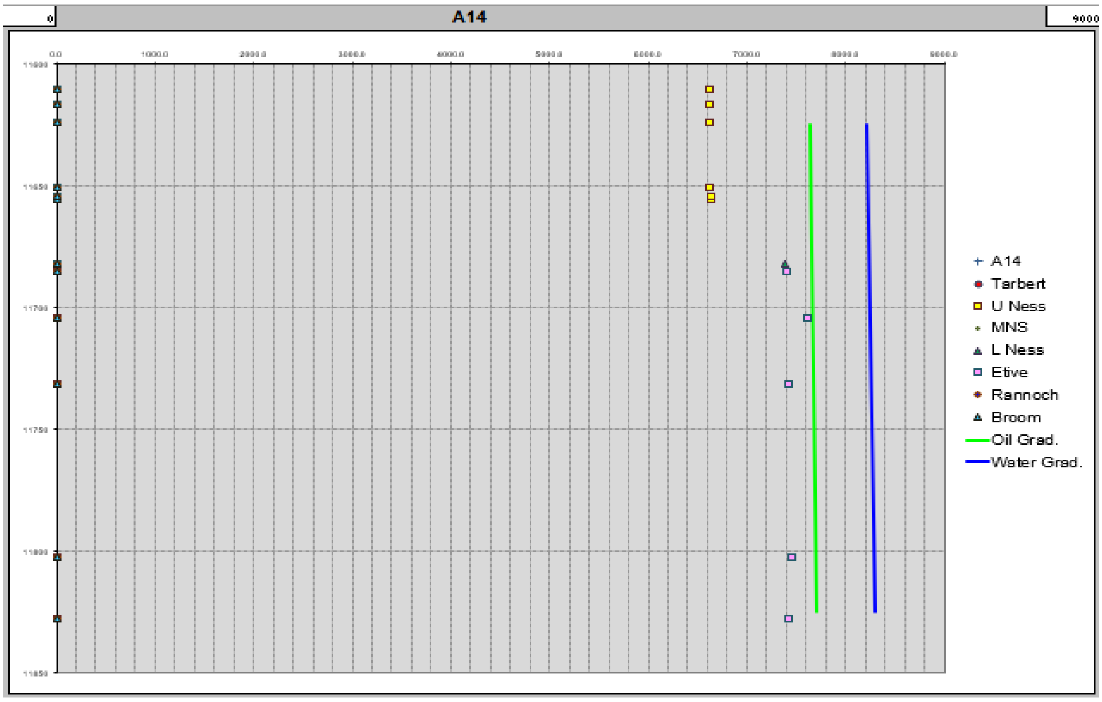


Figure iv)a - Repeat Formation Tester for A14

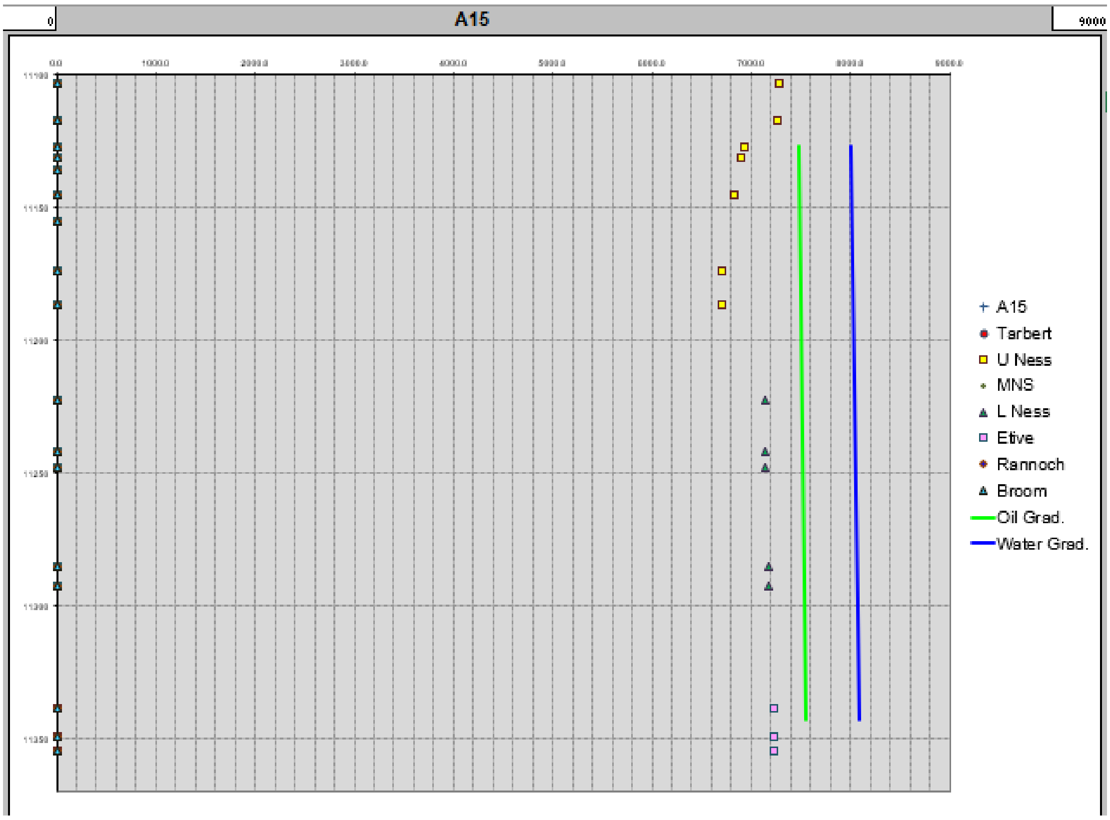


Figure iv)b - Repeat Formation Tester for A15

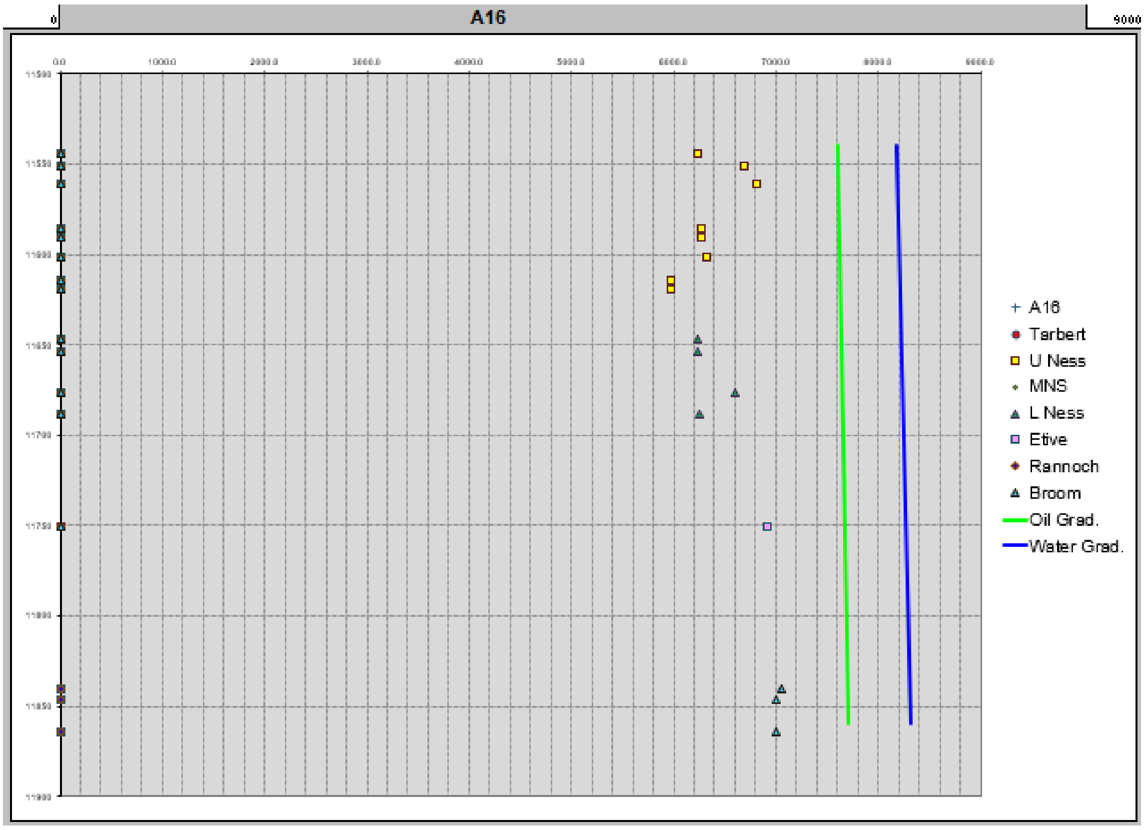


Figure iv)c - Repeat Formation Tester for A16

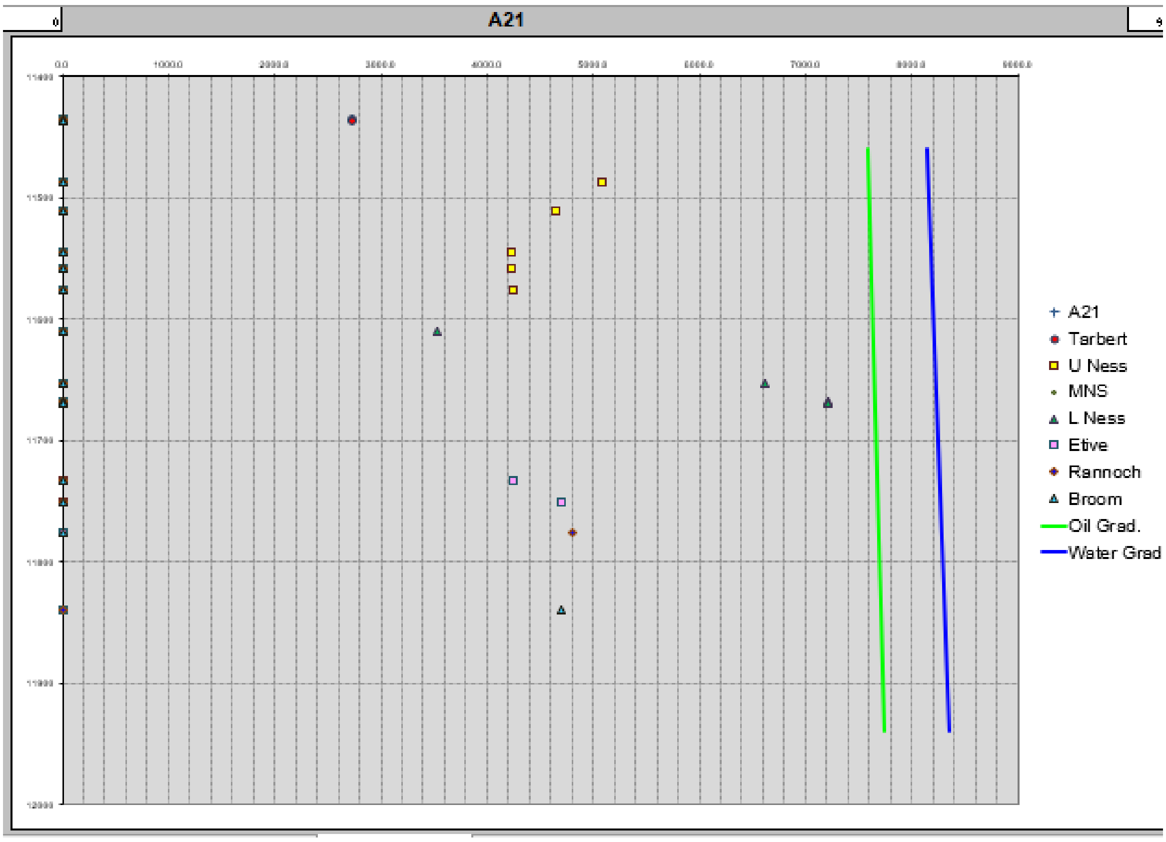


Figure iv)d - Repeat Formation Tester for A21

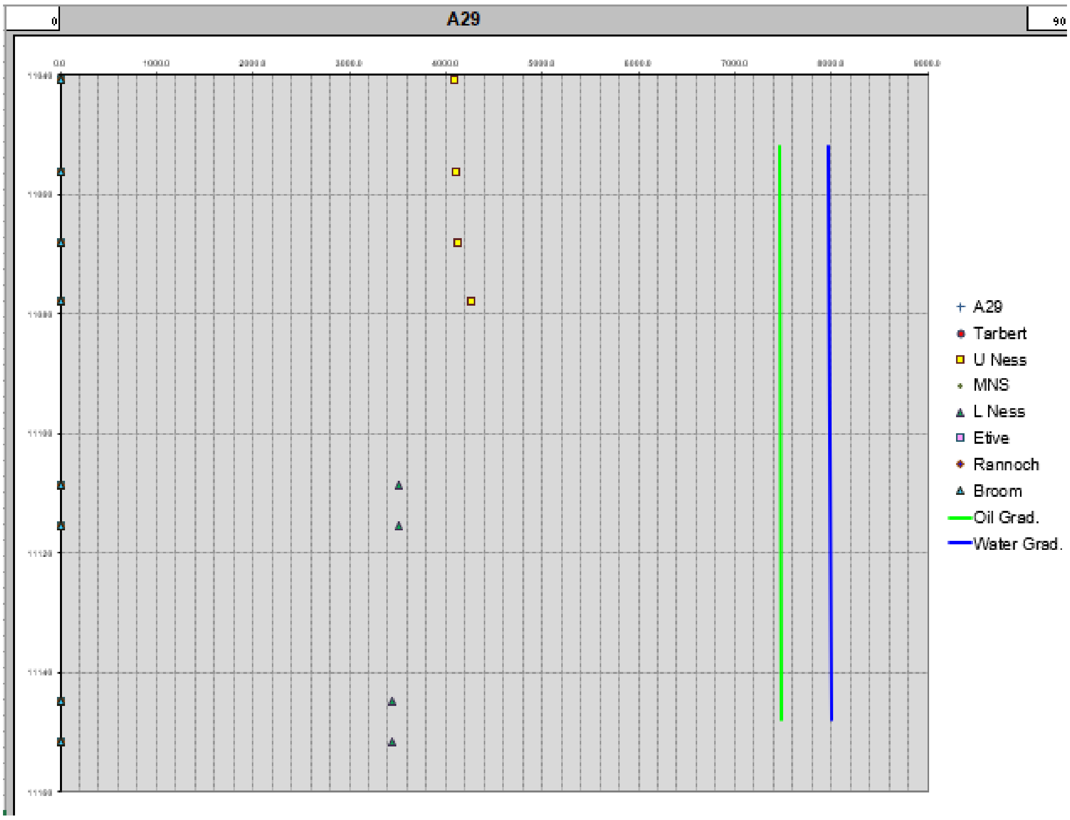


Figure iv)e - Repeat Formation Tester for A29

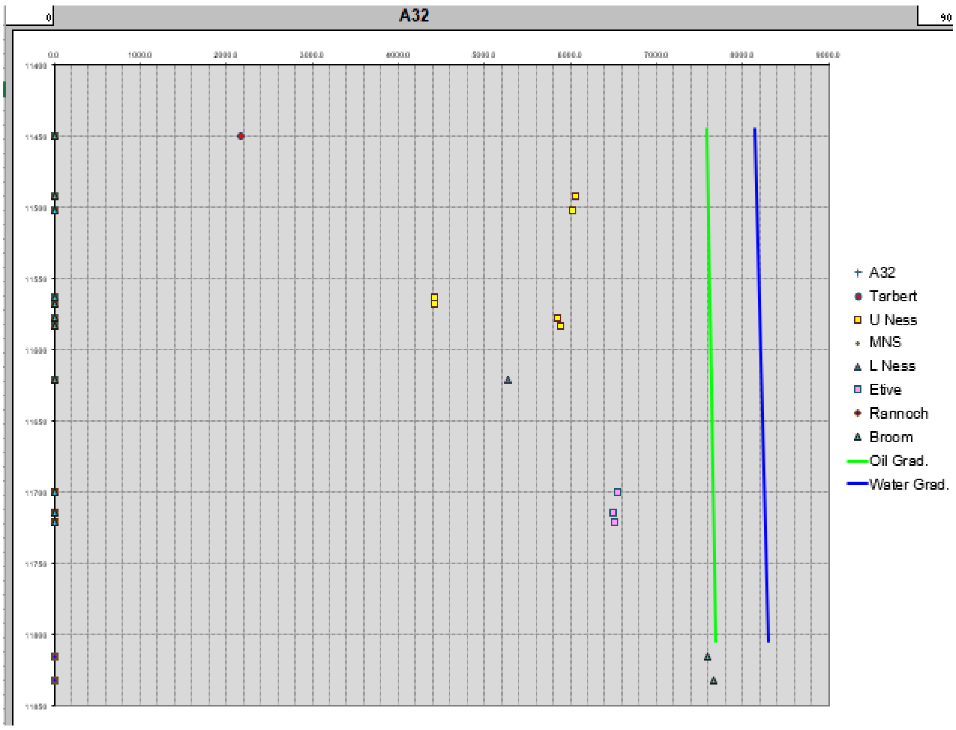


Figure iv)f - Repeat Formation Tester for A32

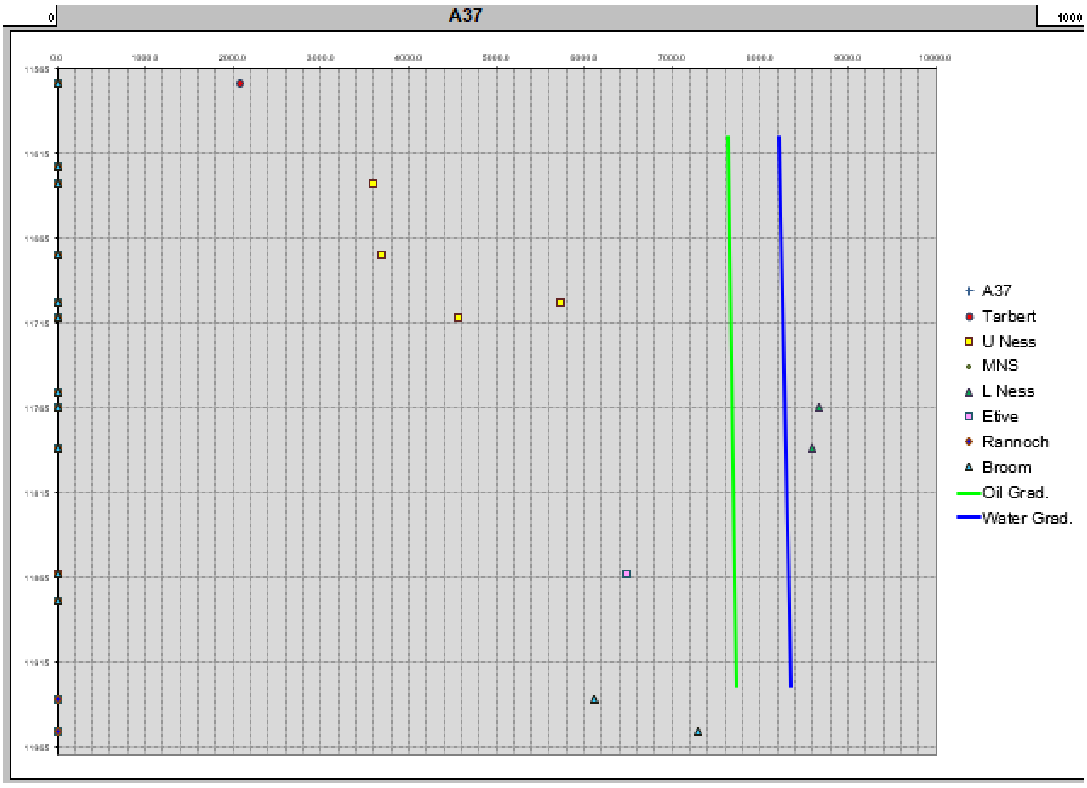


Figure iv) g - Repeat Formation Tester for A37

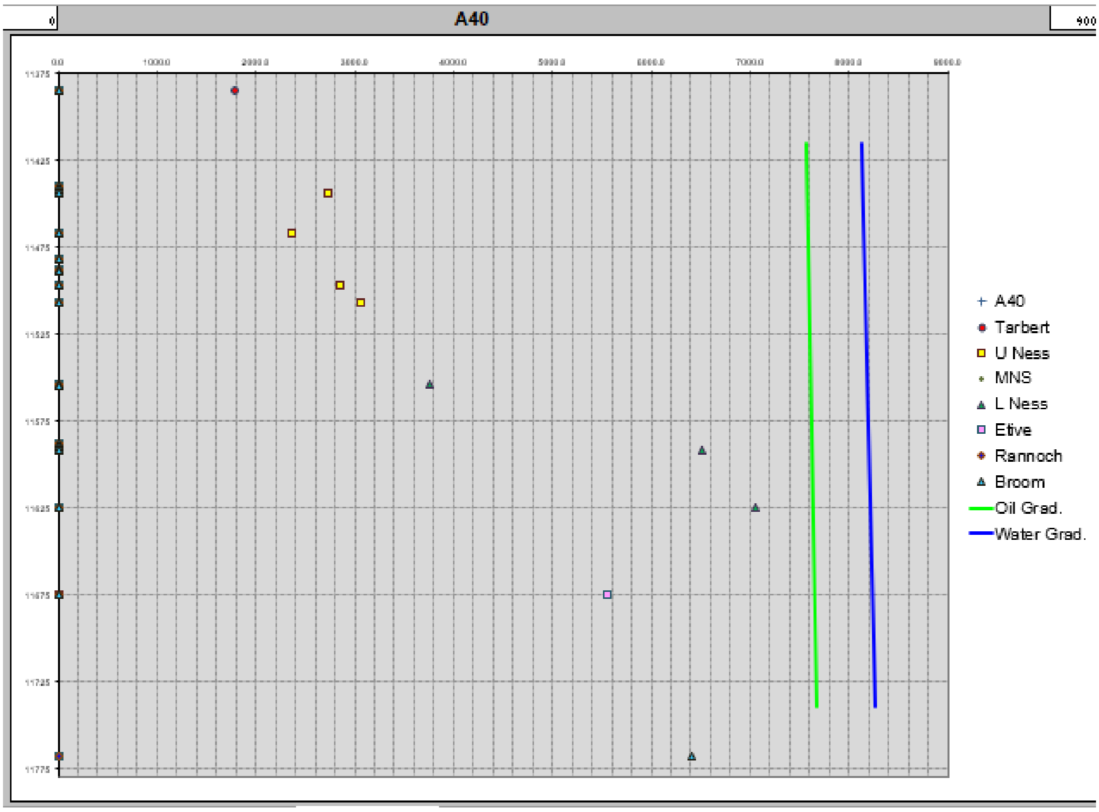


Figure iv)h - Repeat Formation Tester for A40

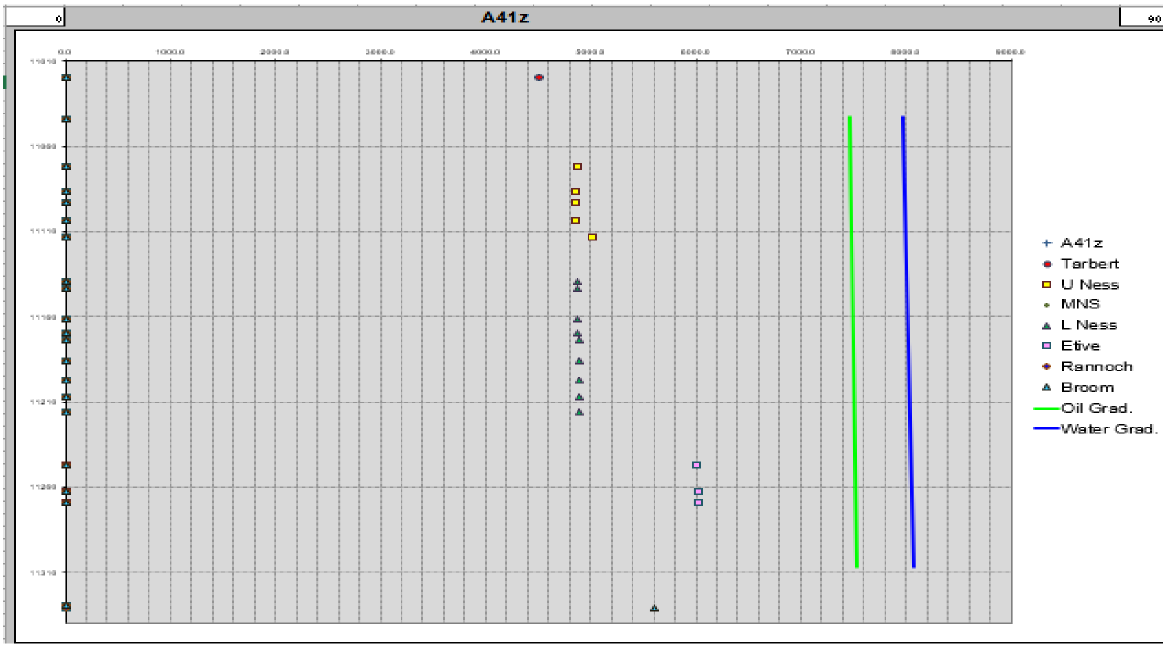


Figure iv)i - Repeat Formation Tester for A41Z

v) CPI Logs with Facies Associations

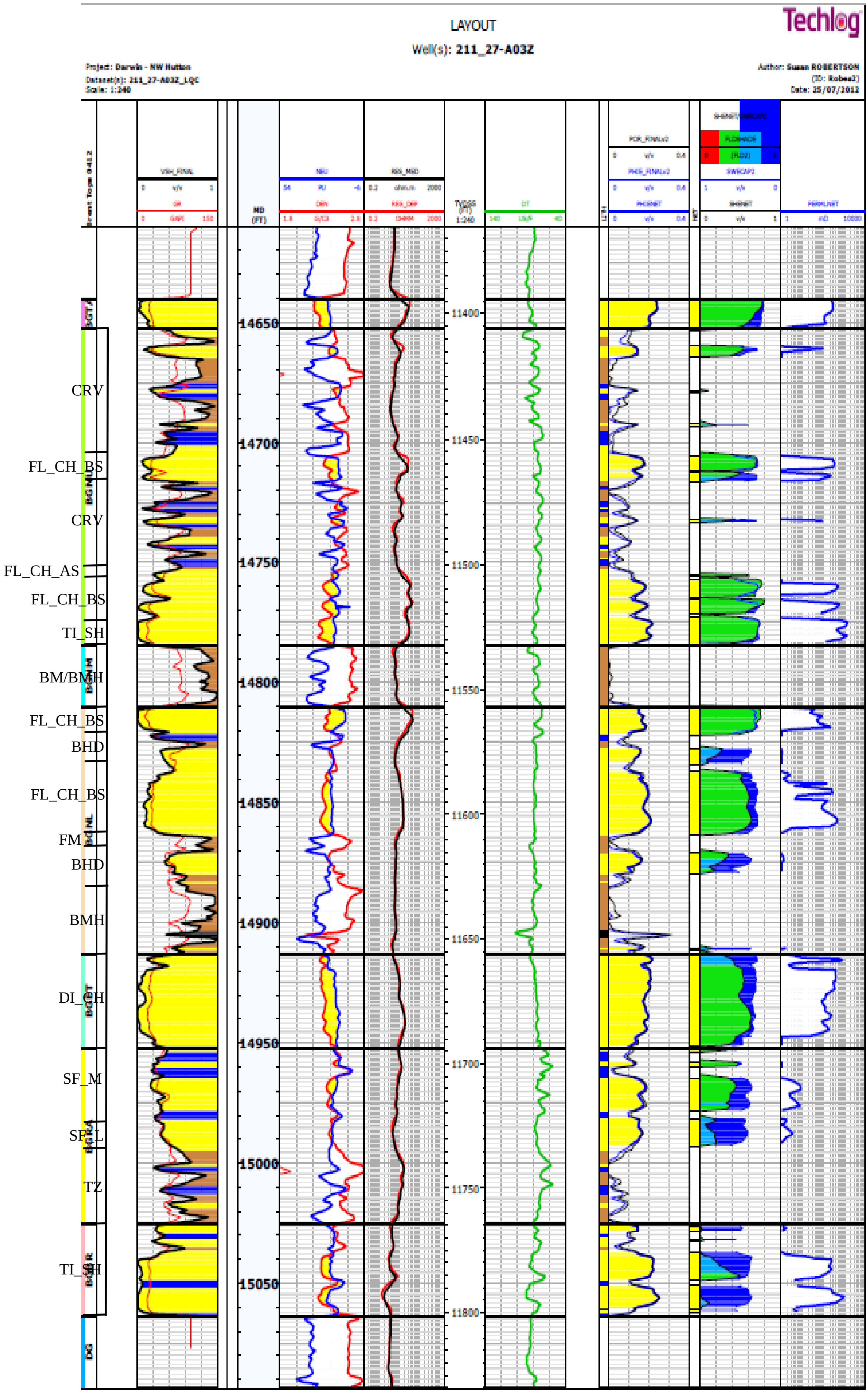


Figure v)a - CPI log of A03Z with facies associations

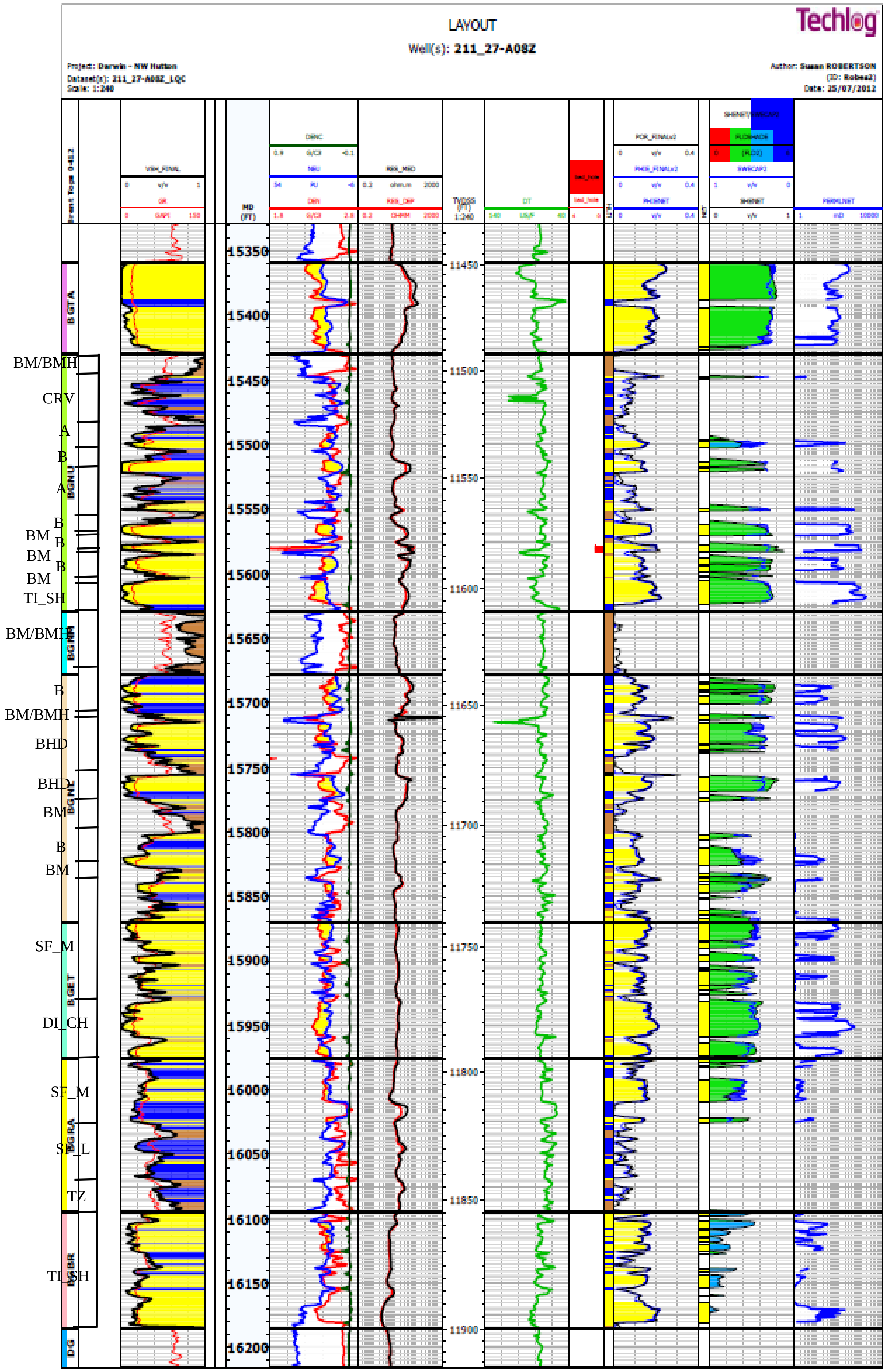


Figure v)b - CPI log of A08Z with facies associations

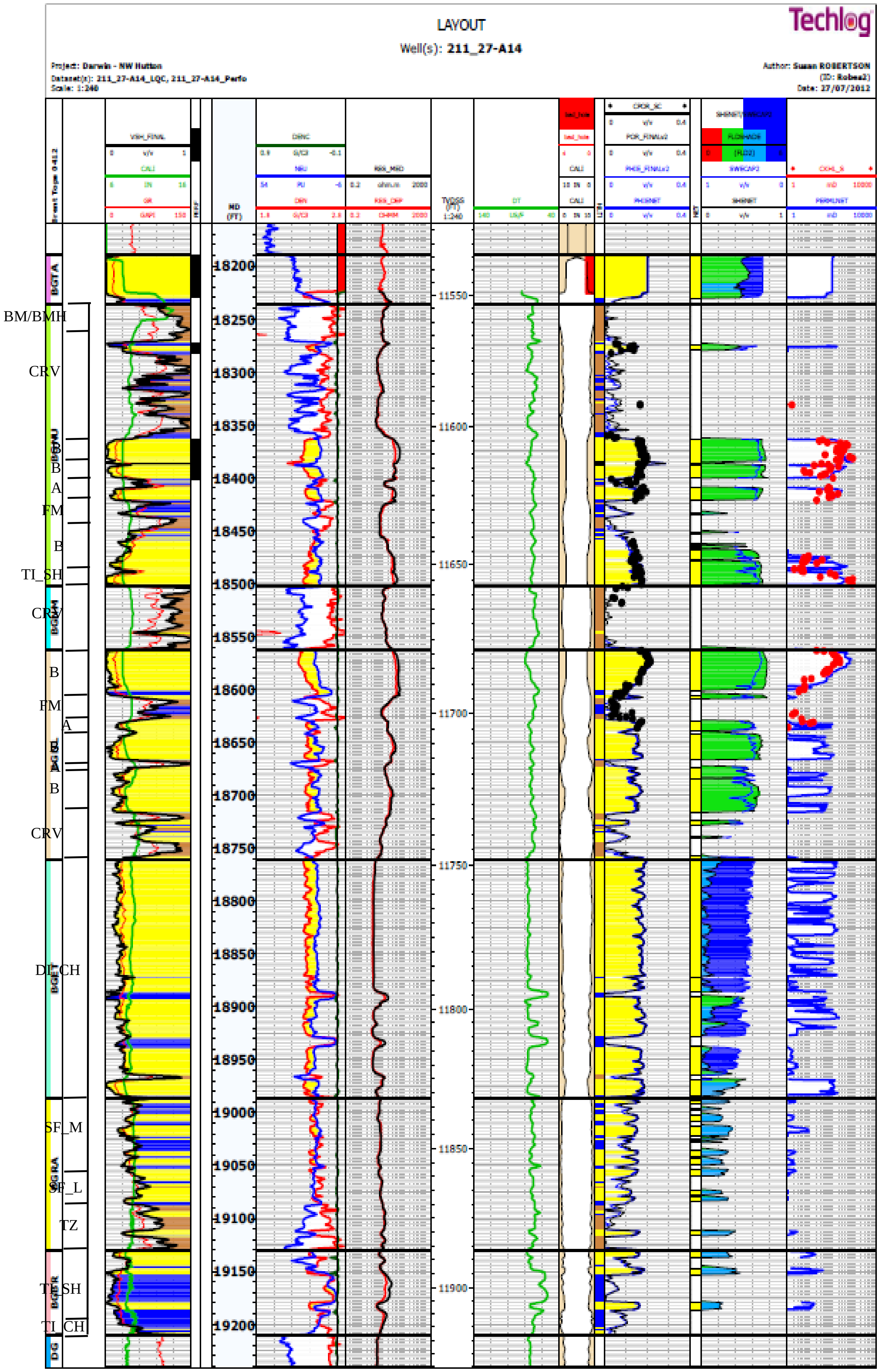


Figure v)c - CPI log of A14 with facies associations

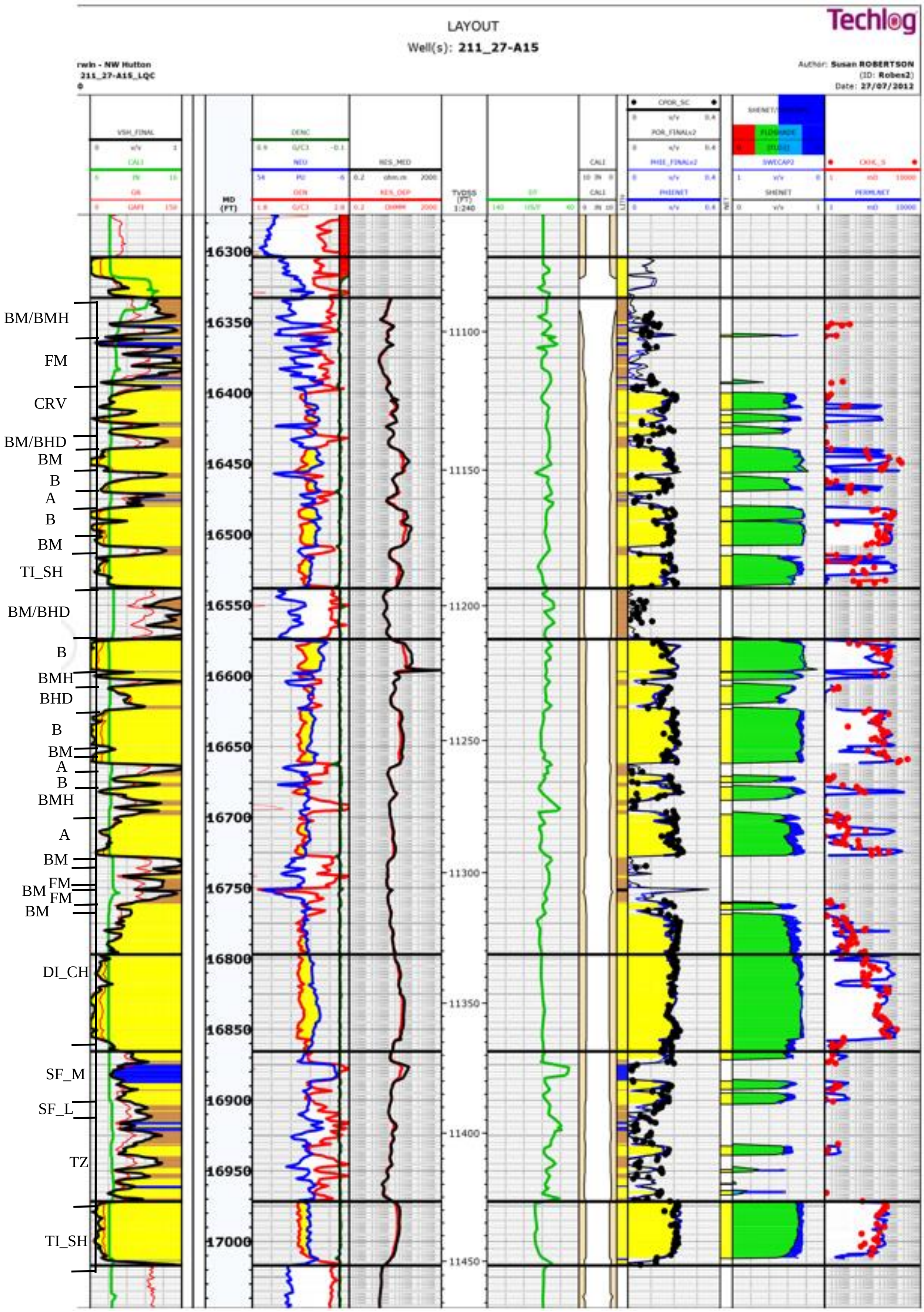


Figure v)d - CPI log of A15 with facies associations

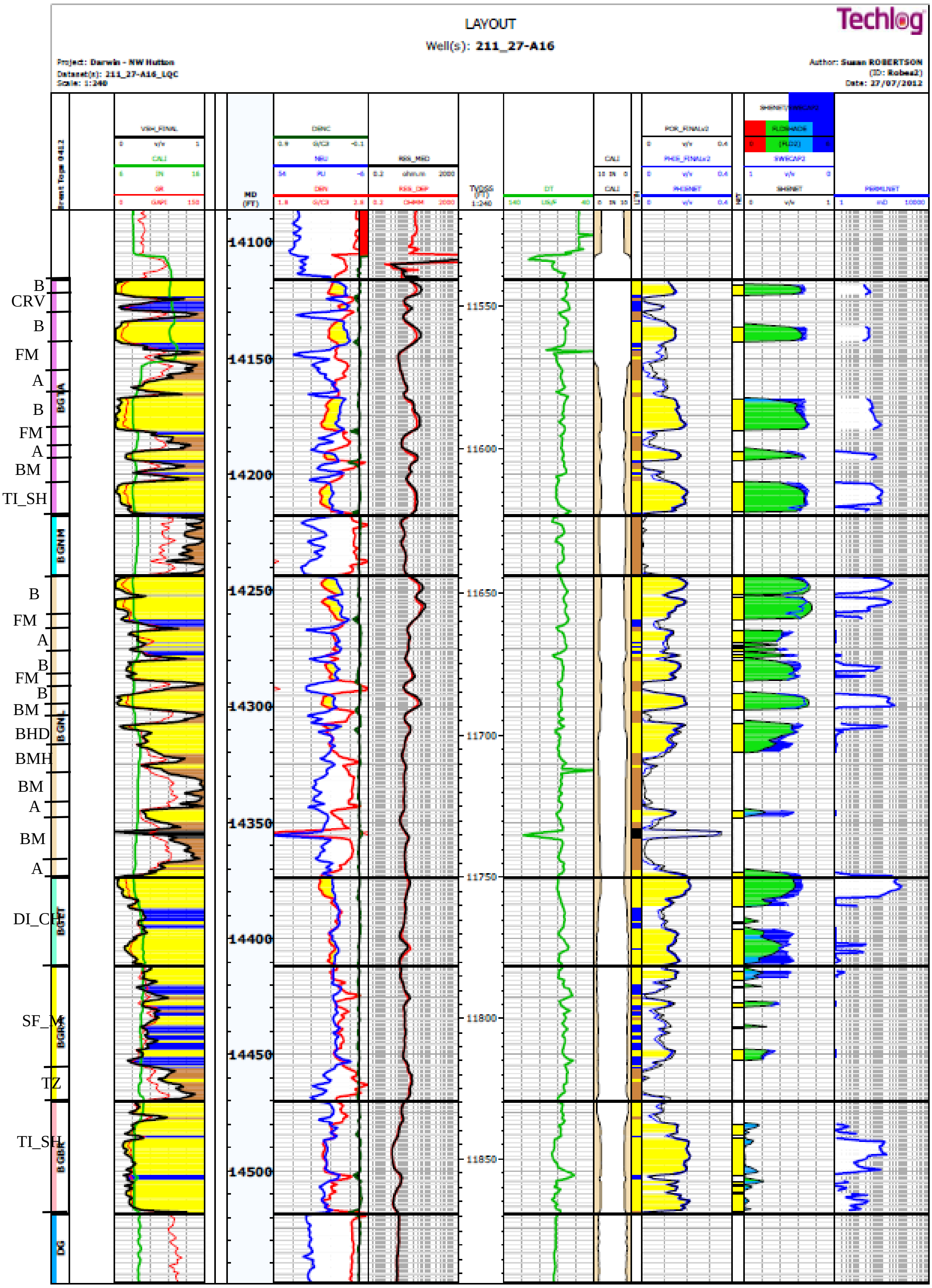


Figure v)e - CPI log of A16 with facies associations

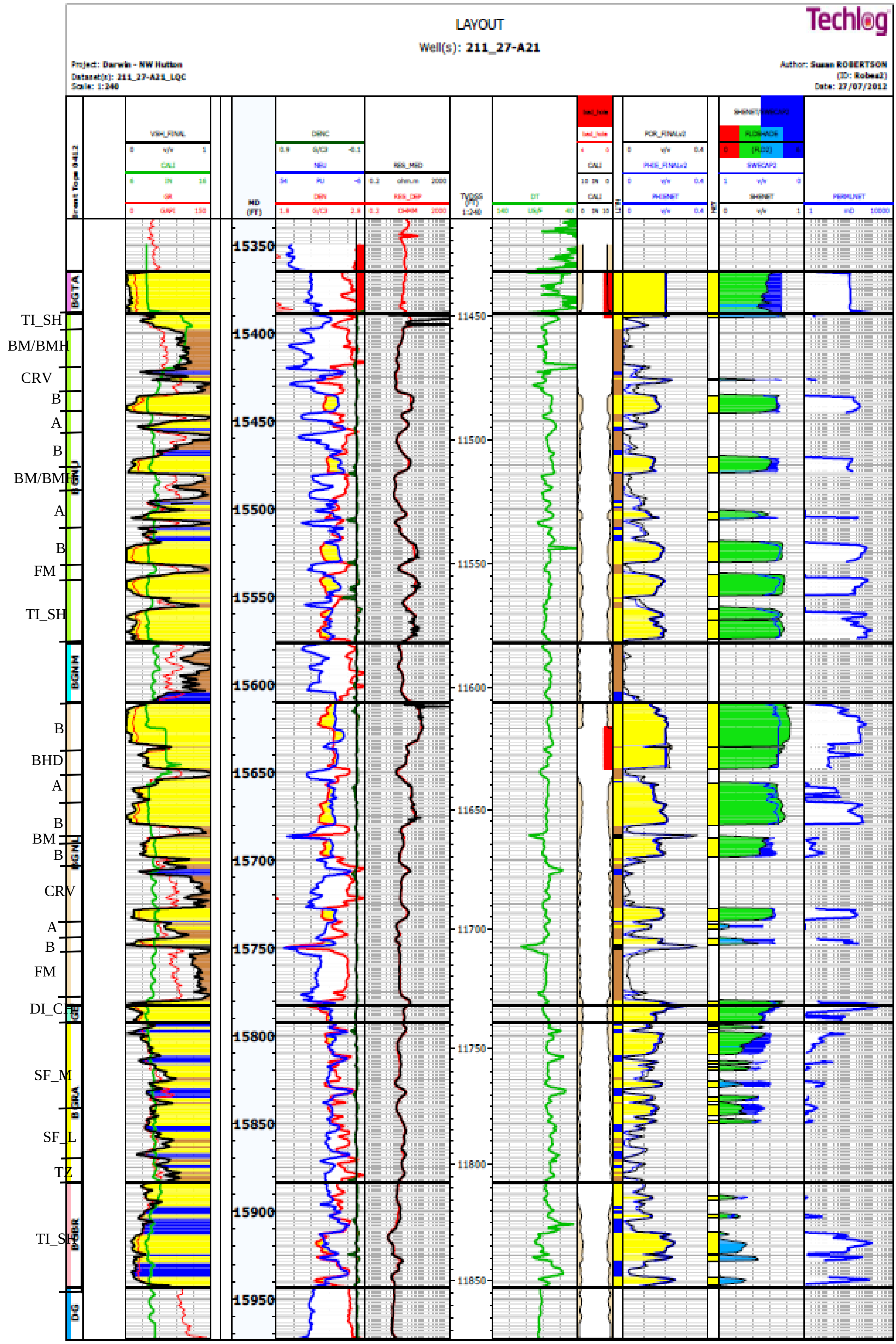


Figure x- CPI log of A21

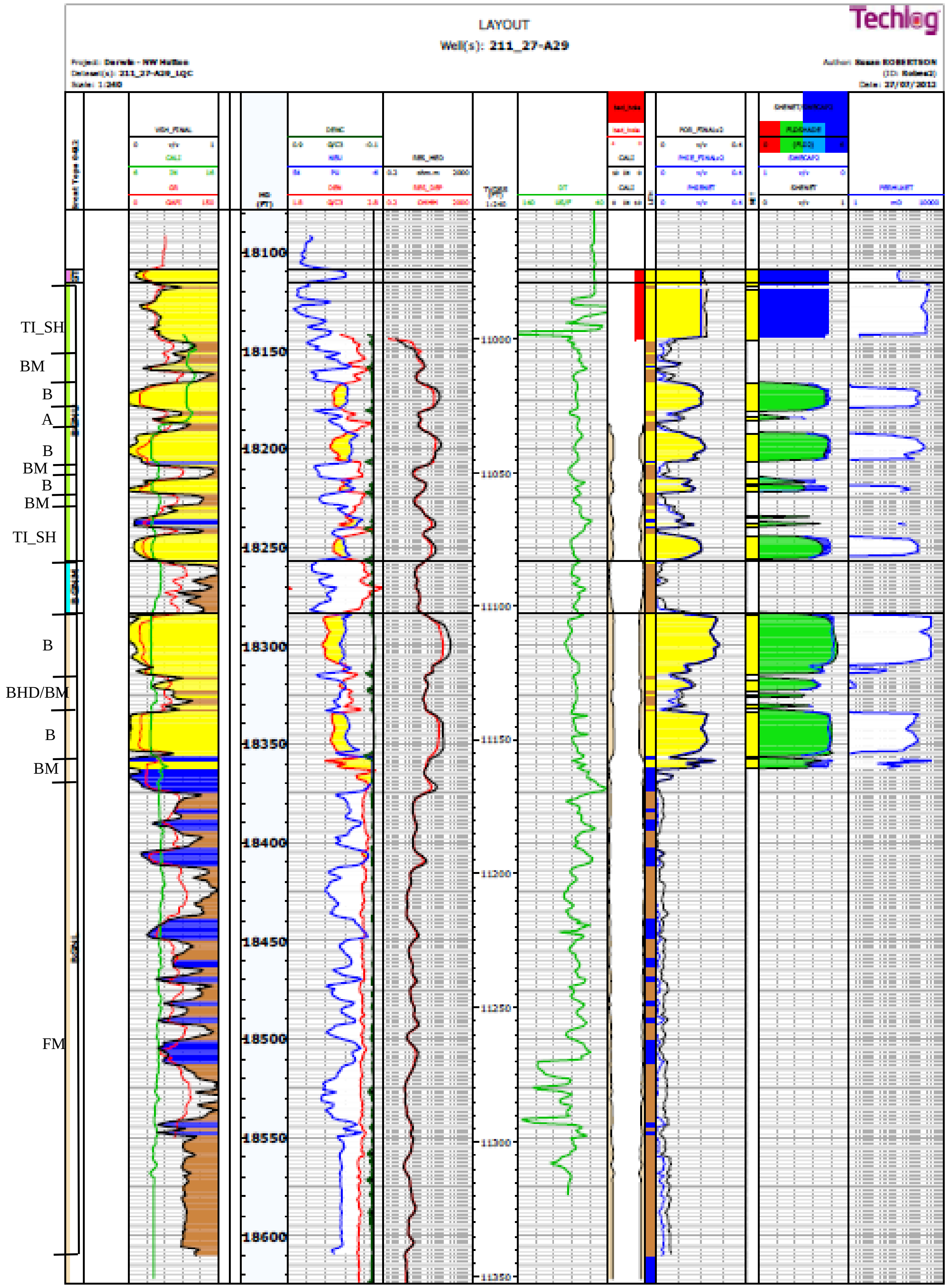


Figure x- CPI log of A29

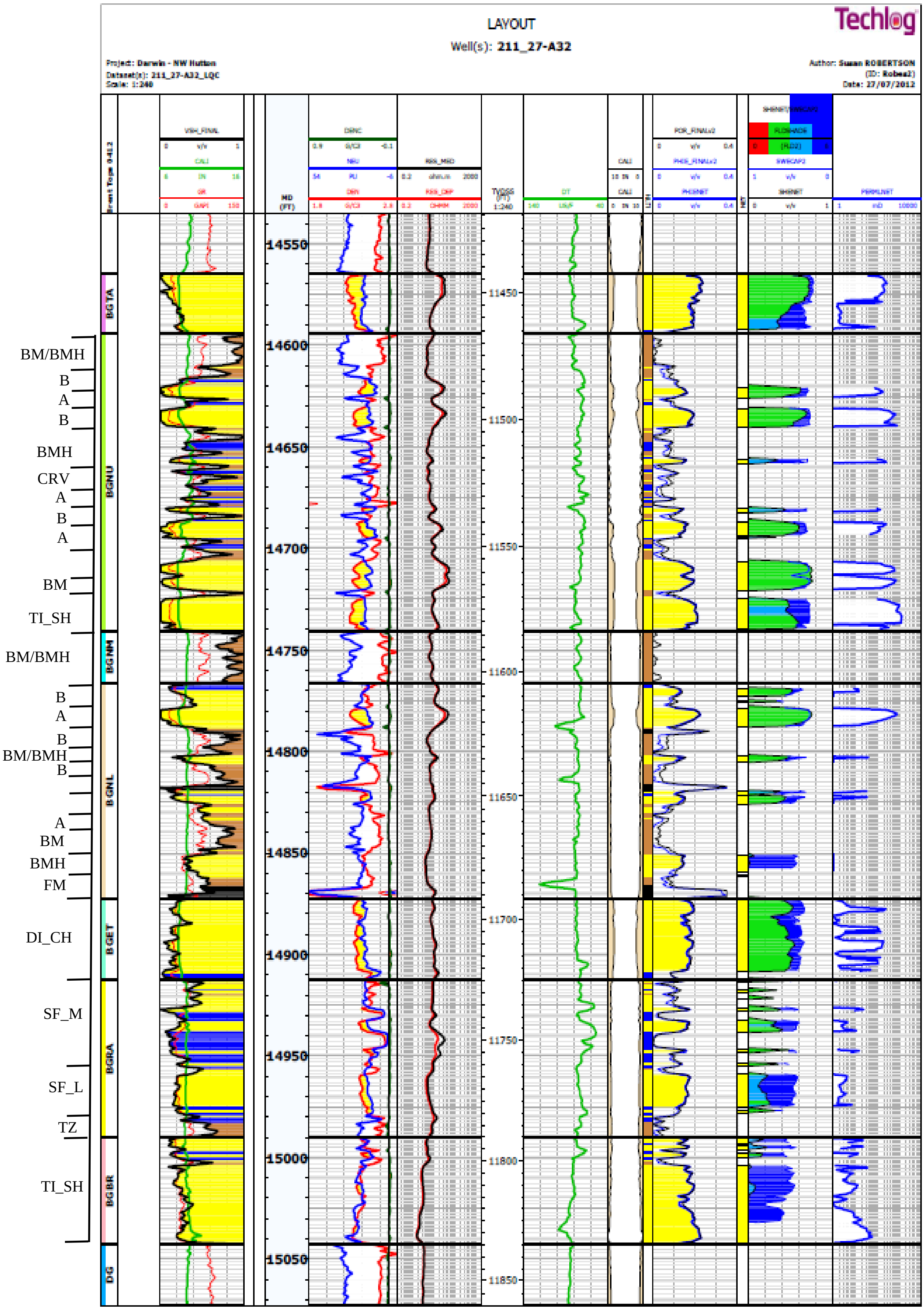


Figure x- CPI log of A32

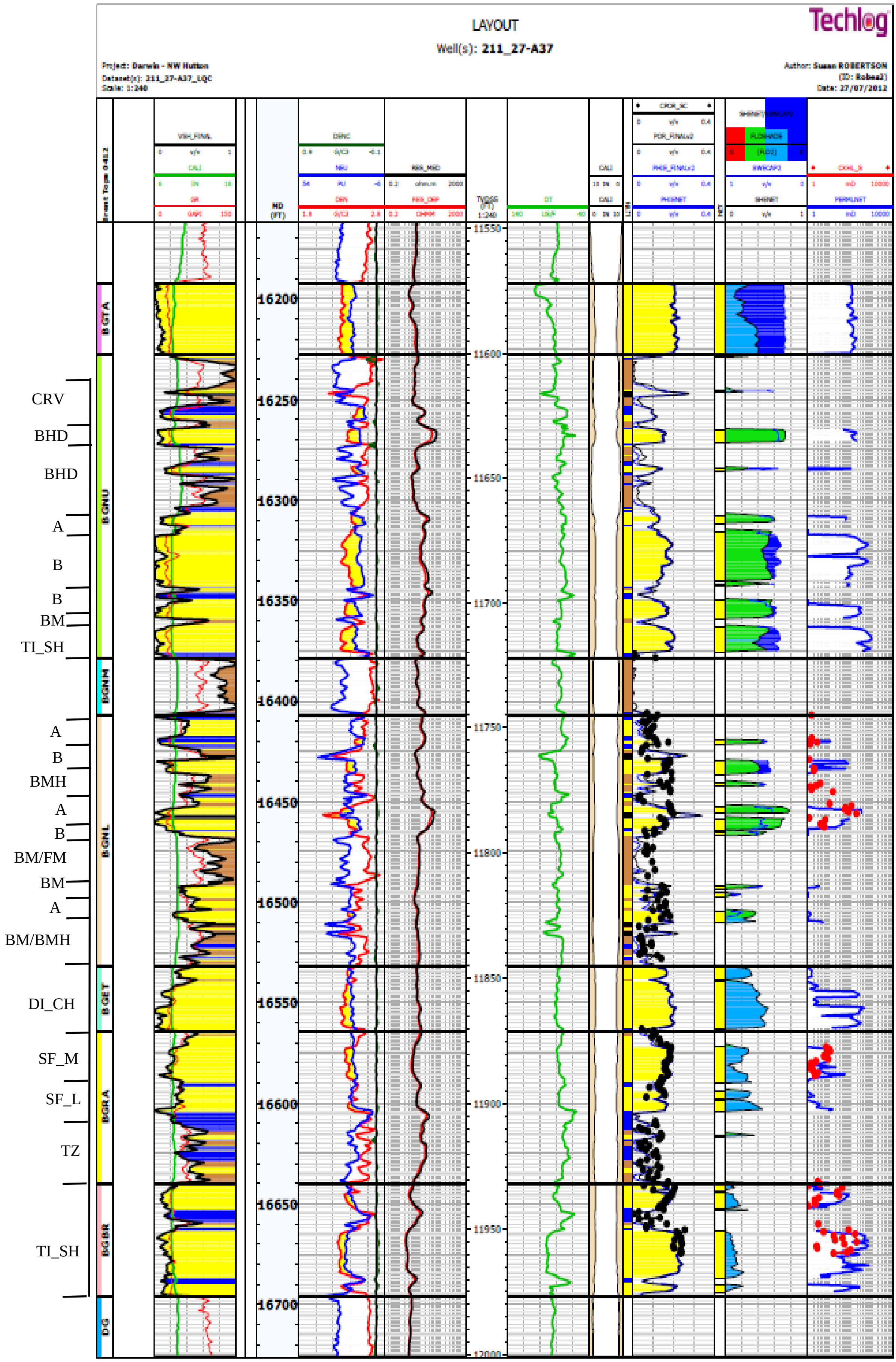


Figure x- CPI log of A37

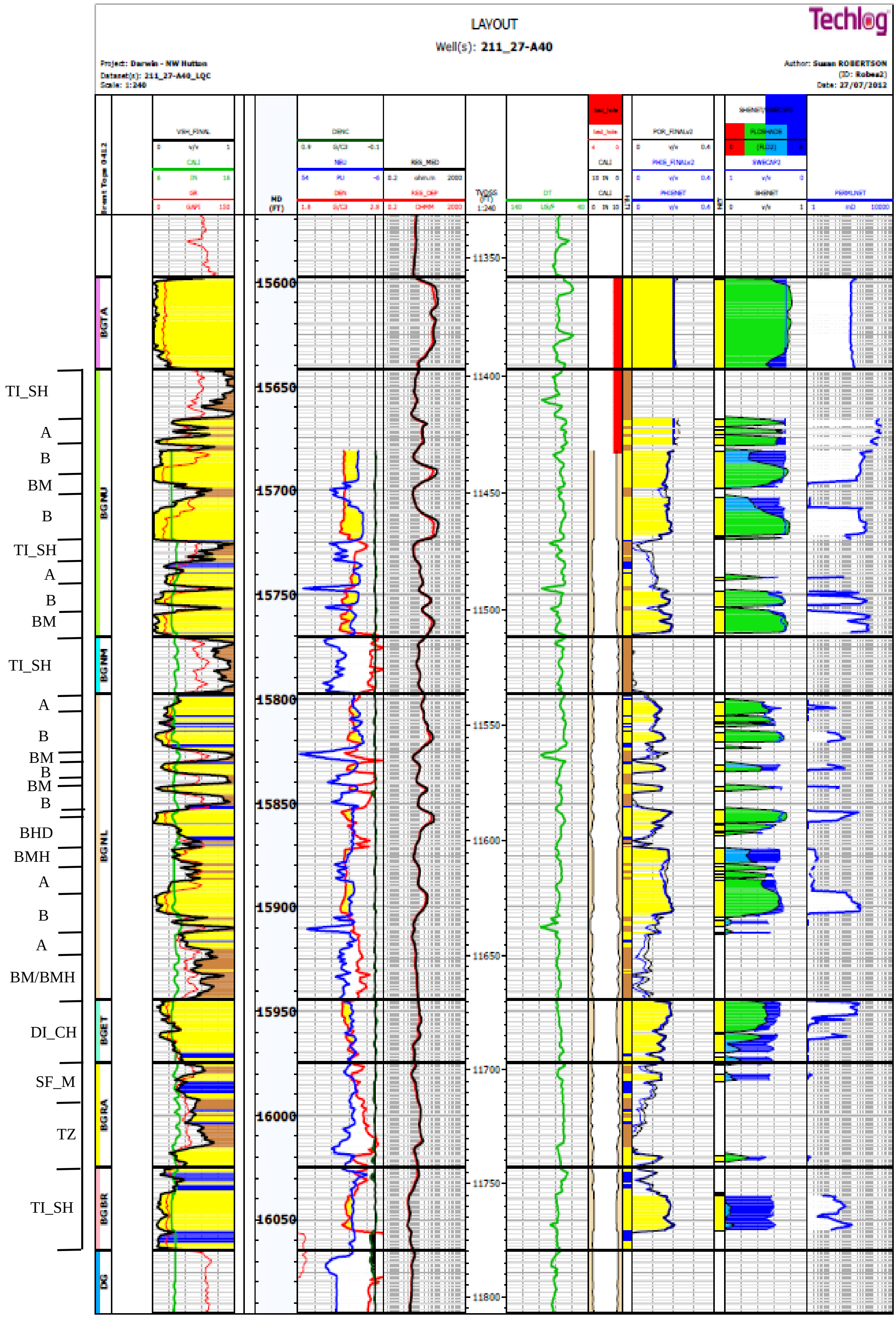


Figure x- CPI log of A40

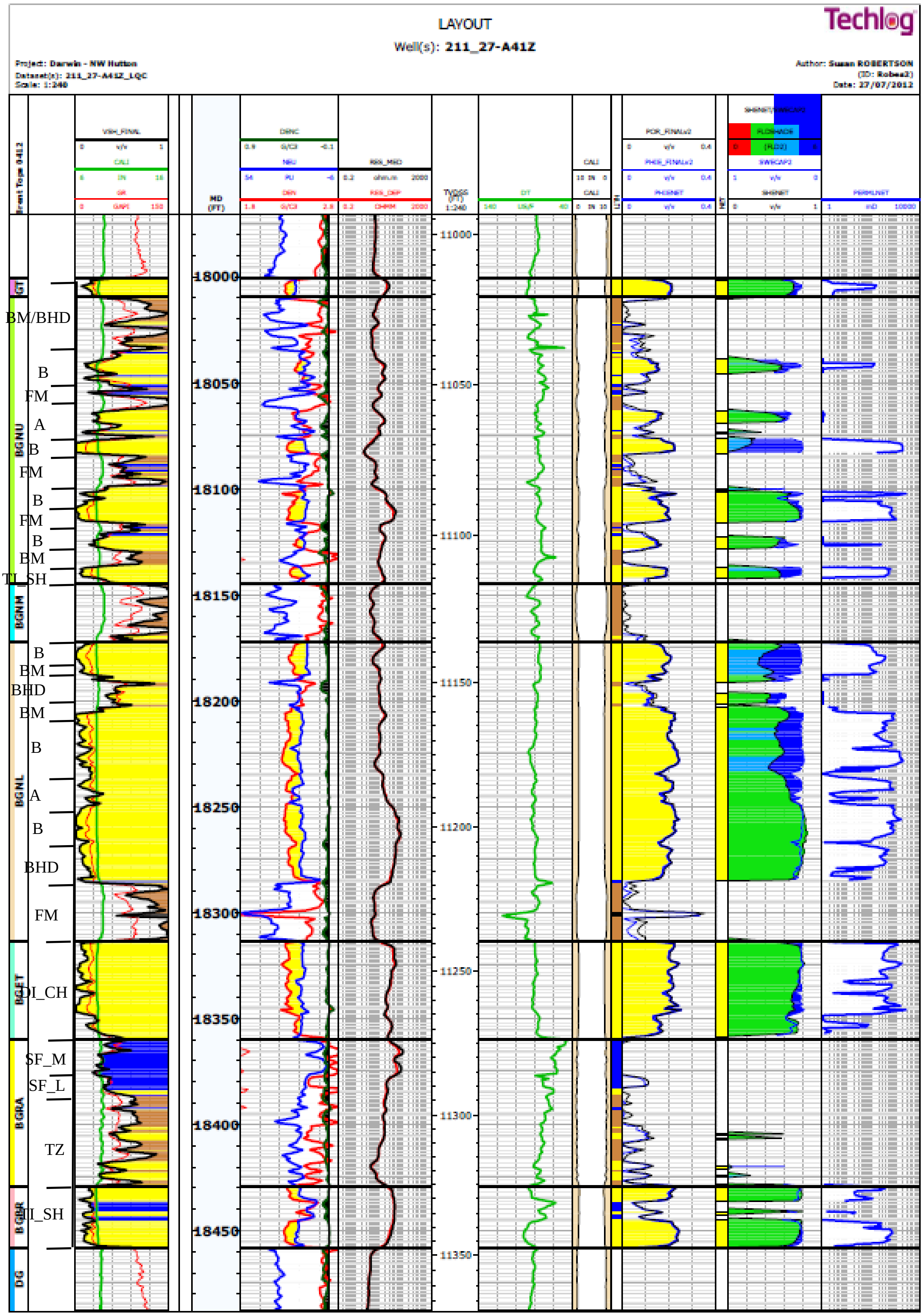


Figure x- CPI log of A41Z

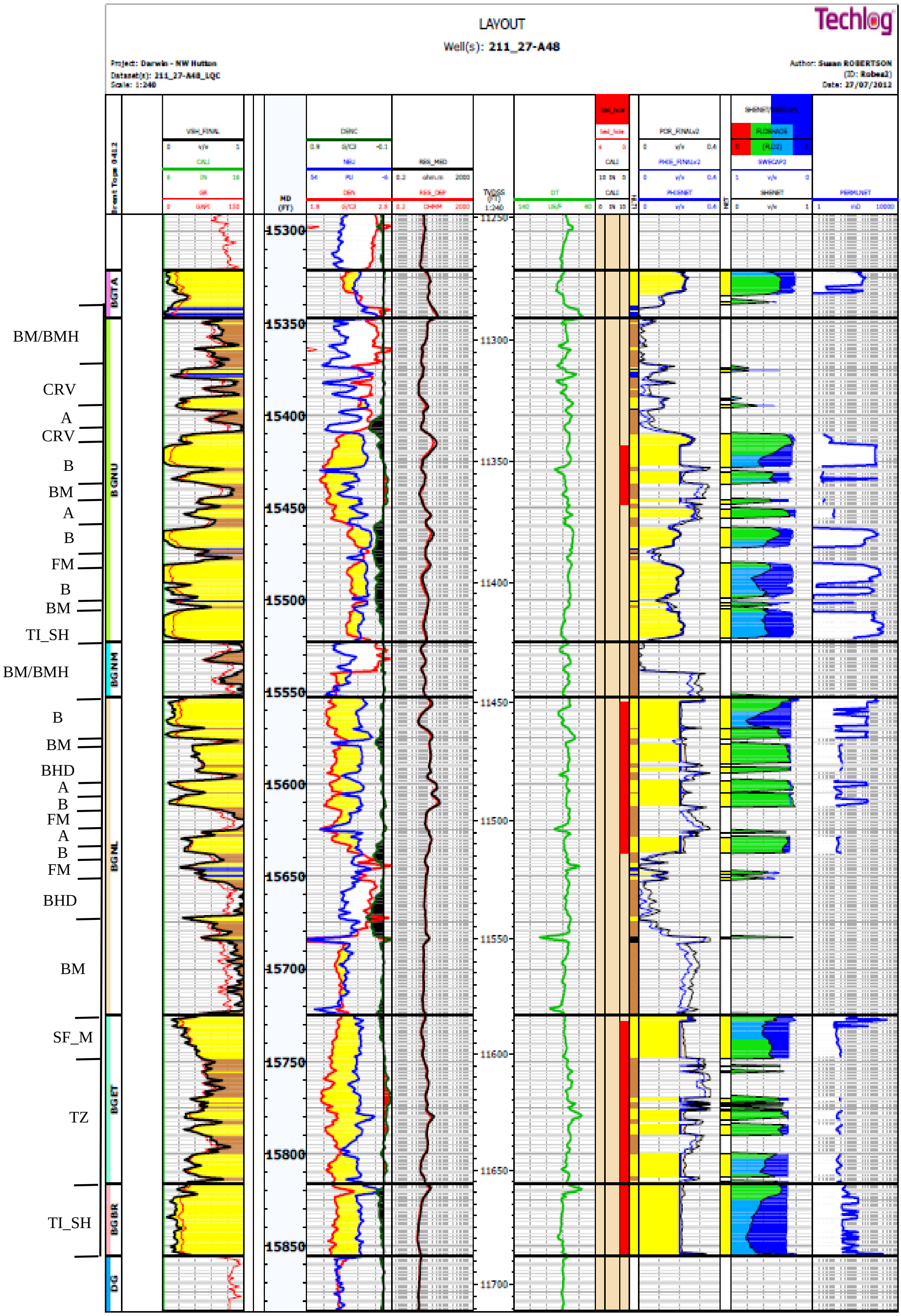


Figure x- CPI log of A48

The following abbreviations (as used by Dundas, 2014) have been applied (Table 5):

CRV	Fluvial floodplain with crevasse splay sand bodies
FM	Fluvial floodplain mud rocks
FL_CH_AS	Fluvial channel - single story, type 'A'
FL_CH_BS	Fluvial channel - single story, type 'B’
FL_CH_AM	Fluvial channel - multi story, type 'A'
FL_CH_BM	Fluvial channel - multi story, type 'B'
BHD_AX	Bay head delta – axial
BHD_DI	Bay head delta - distal, marginal
BMH	Bay margin heterolithic
BM	Bay margin / bay floor mud
DI_CH	Distributary channel
TI_SH	Tidal shoal
TI_CH	Tidal channel
SF_U	Upper shoreface - tidally-influenced
SF_M	Middle shoreface
SF_L	Lower shoreface
TZ	Offshore transition zone

Table 5- Abbreviations of facies associations

vii) Production Data

A03Z

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Jul-83	31,008	2,747	21
Aug-83	32,989	2,673	72
Sep-83	19,847	1,865	136
Oct-83	11,161	959	85
Nov-83	10,770	836	102
Dec-83	5,301	566	79
Jan-84	2,573	182	48
Feb-84	1,977	127	27
Mar-84	1,631	99	15
Apr-84	1,467	96	51
May-84	16,337	1,460	599
Jun-84	12,250	959	539
Jul-84	6,159	412	39
Aug-84	1,675	100	5
Sep-84	853	65	0
Oct-84	11	1	0
Nov-84	1,786	86	260
Dec-84	14,557	1,190	1,900
Jan-85	11,973	856	592
Feb-85	7,519	431	303
Mar-85	6,511	306	93
Apr-85	4,611	297	259
May-85	3,696	161	118
Jun-85	4,005	208	85
Jul-85	3,585	207	265
Aug-85	3,622	208	18
Sep-85	3,416	190	22
Oct-85	8,829	656	517
Nov-85	5,627	395	16
Dec-85	3,408	227	88
Jan-86	3,157	170	146
Feb-86	2,416	154	246
Mar-86	3,062	199	518
Apr-86	6,161	444	976
May-86	4,966	338	917
Jun-86	4,501	346	810
Jul-86	4,311	318	670
Aug-86	3,997	318	1,963
Sep-86	4,242	220	1,412

Oct-86	3,657	133	650
Nov-86	3,317	117	659
Dec-86	3,916	178	409
Jan-87	3,007	168	477
Feb-87	471	27	110
Mar-87	1,253	97	423
Apr-87	2,578	155	484
May-87	4,006	259	576
Jun-87	3,597	196	607
Jul-87	4,061	192	527
Aug-87	3,140	72	601
Sep-87	2,360	69	419
Oct-87	1,782	71	464
Nov-87	1,500	110	991
Dec-87	2,430	178	1,205
Jan-88	1,935	178	1,161
Feb-88	1,833	166	989
Mar-88	2,617	392	1,327
Apr-88	2,627	400	1,236
May-88	2,073	380	1,447
Jun-88	1,252	164	1,227
Jul-88	1,774	256	1,248
Aug-88	728	100	512
Sep-88	0	0	0
Oct-88	1,262	213	801
Nov-88	726	125	1
Dec-88	280	48	1
Jan-89	143	25	0
Feb-89	0	0	0
Mar-89	52	9	0
Apr-89	99	17	0
May-89	0	0	0
Jun-89	10	1	0
Jul-89	53	9	0
Aug-89	0	0	0
Sep-89	0	0	0
Oct-89	0	0	0

A08Z

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Oct-83	0	0	0
Nov-83	52,115	5,450	11

Dec-83	52,192	4,827	1,340
Jan-84	32,080	2,515	716
Feb-84	27,554	1,954	1,490
Mar-84	27,835	1,915	2,347
Apr-84	25,573	1,827	1,074
May-84	19,968	1,487	818
Jun-84	20,775	1,414	648
Jul-84	20,017	1,282	170
Aug-84	14,833	871	548
Sep-84	4,038	267	2,099
Oct-84	19,658	1,292	256
Nov-84	19,317	1,033	324
Dec-84	17,748	909	431
Jan-85	18,451	1,633	339
Feb-85	15,001	1,448	321
Mar-85	14,500	1,202	222
Apr-85	13,583	809	162
May-85	9,743	778	24
Jun-85	13,989	1,168	269
Jul-85	12,839	994	259
Aug-85	10,497	771	56
Sep-85	11,733	838	99
Oct-85	13,216	919	300
Nov-85	11,954	855	166
Dec-85	12,232	943	277
Jan-86	12,523	977	184
Feb-86	2,788	201	171
Mar-86	13,820	1,097	1,078
Apr-86	14,920	1,238	158
May-86	15,082	1,188	470
Jun-86	14,899	1,174	276
Jul-86	14,913	1,216	465
Aug-86	14,925	1,214	298
Sep-86	15,292	1,034	250
Oct-86	15,768	1,002	203
Nov-86	14,629	947	201
Dec-86	15,961	1,132	157
Jan-87	16,173	1,112	6
Feb-87	7,008	515	14
Mar-87	15,613	1,161	3
Apr-87	15,529	1,037	6
May-87	15,721	952	1
Jun-87	14,181	953	1
Jul-87	15,148	1,028	1
Aug-87	14,609	985	0

Sep-87	13,282	956	2
Oct-87	18,345	1,257	2
Nov-87	16,944	1,261	34
Dec-87	15,823	1,152	416
Jan-88	16,007	1,334	152
Feb-88	13,828	1,055	332
Mar-88	14,752	1,384	1,368
Apr-88	13,284	1,075	1,891
May-88	12,602	1,027	2,595
Jun-88	11,705	1,028	3,858
Jul-88	10,840	823	4,012
Aug-88	11,333	1,077	4,177
Sep-88	9,981	945	3,866
Oct-88	8,068	771	4,291
Nov-88	6,842	674	4,979
Dec-88	8,155	879	5,158
Jan-89	7,032	851	5,663
Feb-89	5,307	688	5,279
Mar-89	7,642	807	5,124
Apr-89	3,811	419	3,344
May-89	0	0	0
Jun-89	4,117	467	4,600
Jul-89	5,095	608	6,957
Aug-89	4,790	524	5,241
Sep-89	2,052	222	2,231
Oct-89	2,132	238	3,143
Jan-91	2	0	4

A14

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Jul-84	11,934	647	6
Aug-84	26,513	1,473	0
Sep-84	25,521	1,469	0
Oct-84	19,201	1,072	152
Nov-84	15,291	959	347
Dec-84	10,759	632	117
Jan-85	8,500	499	216
Feb-85	5,262	290	73
Mar-85	3,883	218	71
Apr-85	10,543	806	84
May-85	10,276	769	213
Jun-85	10,330	763	81

Jul-85	9,813	659	133
Aug-85	8,995	530	72
Sep-85	8,609	587	39
Oct-85	7,243	452	51
Nov-85	6,037	326	73
Dec-85	7,074	432	64
Jan-86	7,039	474	19
Feb-86	4,130	265	0
Mar-86	8,372	629	2,682
Apr-86	15,288	1,221	9,919
May-86	14,541	1,138	293
Jun-86	13,201	1,015	184
Jul-86	12,055	906	69
Aug-86	8,348	577	0
Sep-86	5,556	303	7
Oct-86	11,256	587	0
Nov-86	10,184	548	0
Dec-86	10,515	594	56
Jan-87	10,699	631	10
Feb-87	4,733	314	8
Mar-87	10,022	652	5
Apr-87	10,623	496	0
May-87	9,837	420	0
Jun-87	8,996	362	9
Jul-87	9,910	587	0
Aug-87	9,866	482	0
Sep-87	9,528	633	0
Oct-87	9,964	614	0
Nov-87	9,185	598	8
Dec-87	8,755	610	0
Jan-88	7,582	587	0
Feb-88	6,921	486	4
Mar-88	7,780	528	9
Apr-88	7,120	564	11
May-88	6,594	517	61
Jun-88	6,973	584	12
Jul-88	6,781	637	37
Aug-88	6,846	673	38
Sep-88	6,108	648	60
Oct-88	5,570	646	50
Nov-88	6,109	794	43
Dec-88	6,241	667	158
Jan-89	5,861	614	286
Feb-89	4,963	696	501
Mar-89	5,820	1,072	451

Apr-89	3,444	573	346
May-89	69	2	6
Jun-89	4,812	672	234
Jul-89	7,365	822	4
Aug-89	6,787	709	11
Sep-89	3,599	296	0
Oct-89	6,222	613	4
Nov-89	5,847	591	18
Dec-89	6,434	651	62
Jan-90	6,455	646	35
Feb-90	6,050	648	53
Mar-90	6,598	673	74
Apr-90	2,360	253	77
May-90	5,786	552	65
Jun-90	4,330	400	34
Jul-90	5,293	432	2
Aug-90	5,458	493	7
Sep-90	5,474	494	11
Oct-90	4,971	438	29
Nov-90	5,216	444	17
Dec-90	31	2	0
Jan-91	1	0	0
Feb-91	2	0	0
Apr-91	0	0	0
May-91	0	0	0
Jun-91	5,009	610	26
Jul-91	6,634	922	47
Aug-91	7,106	988	50
Sep-91	5,056	703	36
Oct-91	8,508	1,162	54
Nov-91	9,884	1,150	0
Dec-91	10,053	1,139	91
Jan-92	8,463	1,027	22
Feb-92	8,019	997	0
Mar-92	6,531	625	5
Apr-92	9,570	813	10
May-92	7,633	957	3
Jun-92	3,439	277	38
Jul-92	8,284	692	19
Aug-92	9,477	882	19
Sep-92	4,836	473	15
Oct-92	6,344	649	18
Nov-92	9,861	1,138	8
Dec-92	10,123	1,292	20
Jan-93	9,466	1,108	9

Feb-93	9,793	1,100	0
Mar-93	9,707	1,128	0
Apr-93	5,663	706	0
May-93	9,410	1,173	5
Jun-93	8,768	1,093	182
Jul-93	10,181	1,368	74
Aug-93	7,242	670	63
Sep-93	8,584	880	192
Oct-93	10,055	1,253	436
Nov-93	7,101	881	220
Dec-93	9,448	1,171	312
Jan-94	11,111	1,012	2,036
Feb-94	4,964	425	1,375
Mar-94	7,643	625	2,663
Apr-94	6,994	68	2,935
May-94	7,136	889	2,088
Jun-94	3,712	659	1,421
Jul-94	2,529	288	812
Aug-94	3,361	419	1,393
Sep-94	2,330	253	894
Oct-94	5,196	647	1,589
Nov-94	835	104	210
Dec-94	5,404	626	1,688
Jan-95	5,776	585	1,615
Feb-95	4,182	506	995
Mar-95	5,911	841	1,975
Apr-95	3,913	238	945
May-95	409	30	155
Jun-95	2,842	208	990
Jul-95	2,372	173	876
Aug-95	2,577	188	1,627
Sep-95	3,091	226	985
Oct-95	4,197	307	2,490
Nov-95	3,855	282	1,584
Dec-95	3,506	256	1,424
Jan-96	3,141	229	1,560
Feb-96	2,131	156	754
Mar-96	1,094	80	185
Apr-96	3,183	233	2,485
May-96	4,498	329	2,658
Jun-96	4,828	353	2,145
Jul-96	4,986	364	2,132
Aug-96	746	54	298
Sep-96	4,381	320	1,822
Oct-96	4,189	306	1,707

Nov-96	4,345	317	2,016
Dec-96	5,062	370	2,982
Jan-97	3,290	240	1,652
Feb-97	1,655	121	1,241
Mar-97	3,353	245	2,175
Apr-97	2,721	199	1,170
May-97	4,319	316	2,295
Jun-97	5,488	401	2,022
Jul-97	5,422	396	1,761
Aug-97	5,597	409	2,422
Sep-97	5,680	415	2,603
Oct-97	4,242	310	2,544
Nov-97	3,517	257	1,746
Dec-97	2,270	166	1,240
Feb-98	1,580	115	1,019
Mar-98	4,696	343	2,346
Apr-98	5,983	437	4,336
May-98	6,421	469	1,779
Jun-98	6,343	463	2,836
Jul-98	2,965	217	700
Aug-98	3,842	281	2,673
Sep-98	2,489	182	2,429
Oct-98	3,298	241	921
Nov-98	3,774	276	760
Dec-98	4,312	315	1,016
Jan-99	4,786	350	2,975
Feb-99	3,671	268	1,445
Mar-99	4,141	303	1,659
Apr-99	4,373	320	4,102
May-99	4,357	318	3,301
Jun-99	6,011	439	1,504

A15

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Jun-84	60,791	4,118	0
Jul-84	82,660	4,983	0
Aug-84	82,307	5,050	0
Sep-84	61,154	4,052	0
Oct-84	55,366	4,120	70
Nov-84	41,268	3,170	12
Dec-84	38,906	3,128	0
Jan-85	35,342	2,751	18

Feb-85	29,289	2,384	0
Mar-85	31,449	2,493	0
Apr-85	28,508	2,274	0
May-85	21,859	1,787	0
Jun-85	17,827	1,541	0
Jul-85	44,001	3,403	0
Aug-85	43,782	2,930	0
Sep-85	41,968	3,300	0
Oct-85	42,445	3,120	0
Nov-85	39,599	2,977	0
Dec-85	46,021	3,728	0
Jan-86	37,571	3,160	0
Feb-86	42,825	3,530	0
Mar-86	41,446	3,397	57
Apr-86	37,649	2,939	0
May-86	36,990	2,972	0
Jun-86	35,562	2,893	0
Jul-86	34,991	2,789	0
Aug-86	37,116	3,285	38
Sep-86	37,077	2,785	952
Oct-86	36,854	2,517	2,004
Nov-86	32,545	2,401	2,276
Dec-86	31,740	2,303	1,844
Jan-87	31,575	2,509	3,259
Feb-87	13,514	1,088	2,072
Mar-87	24,112	2,063	8,370
Apr-87	25,478	2,234	22,661
May-87	24,276	1,797	20,233
Jun-87	20,471	1,657	19,950
Jul-87	20,477	1,774	22,058
Aug-87	19,627	1,889	22,647
Sep-87	17,959	1,860	23,507
Oct-87	15,897	1,416	27,619
Nov-87	11,585	986	26,258
Dec-87	10,478	1,095	25,782
Jan-88	8,873	1,043	25,679
Feb-88	7,745	766	26,110
Mar-88	5,746	583	30,209
Apr-88	6,042	743	33,809
May-88	5,982	753	30,442
Jun-88	5,160	653	31,656
Jul-88	5,016	789	33,047
Aug-88	10,631	1,315	29,992
Sep-88	14,325	1,597	23,714
Oct-88	11,540	1,420	19,368

Nov-88	8,496	1,038	17,714
Dec-88	5,822	607	18,676
Jan-89	3,900	819	18,105

A16

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Jul-84	4,640	329	16
Aug-84	18,747	1,303	6
Sep-84	15,975	1,163	0
Oct-84	15,812	1,200	17
Nov-84	13,675	1,054	15
Dec-84	1,181	87	0

A21

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Feb-85	7,236	459	30
Mar-85	11,663	746	0

A29

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Dec-85	0	0	0
Feb-86	10,437	946	0
Mar-86	36,576	2,845	0
Apr-86	37,268	2,967	0
May-86	35,080	2,727	0
Jun-86	34,826	2,908	0
Jul-86	34,978	2,817	0
Aug-86	34,323	3,010	0
Sep-86	35,462	2,592	0
Oct-86	36,899	2,664	144
Nov-86	33,372	2,453	1,174
Dec-86	31,349	2,513	4,458
Jan-87	31,537	2,715	4,663
Feb-87	11,316	1,036	470
Mar-87	24,364	2,315	10,399
Apr-87	23,238	1,971	12,176
May-87	23,431	1,755	13,777
Jun-87	20,203	1,703	15,440

Jul-87	21,135	1,937	18,522
Aug-87	19,391	1,514	21,095
Sep-87	17,227	1,743	22,251
Oct-87	17,284	1,913	23,441
Nov-87	15,313	1,380	23,018
Dec-87	13,979	1,258	23,322
Jan-88	13,221	1,513	23,668
Feb-88	8,733	916	15,661
Mar-88	11,581	1,097	23,436
Apr-88	9,768	948	21,222
May-88	9,607	944	22,057
Jun-88	6,873	576	18,853
Jul-88	7,557	803	19,379
Aug-88	8,523	1,087	19,539
Sep-88	6,495	736	13,054
Oct-88	5,532	649	11,251
Nov-88	1,925	272	4,144
Dec-88	7,141	853	14,698
Jan-89	4,415	738	11,679
Feb-89	4,763	1,072	21,017
Mar-89	3,008	521	15,952
Apr-89	3,397	588	14,820
May-89	0	0	0
Jun-89	4,766	811	19,305
Jul-89	7,559	1,277	29,443
Aug-89	7,254	1,161	30,553
Sep-89	3,405	472	15,677
Oct-89	6,716	808	31,770
Nov-89	5,707	829	24,842
Dec-89	7,350	1,362	37,271
Jan-90	7,055	1,453	36,569
Feb-90	6,776	1,508	35,222
Mar-90	6,783	1,684	38,118
Apr-90	4,508	683	25,904
May-90	4,308	431	24,219
Jun-90	3,165	329	17,626
Jul-90	2,389	202	14,796
Aug-90	2,512	208	12,156
Sep-90	1,915	178	8,443
Oct-90	1,422	151	5,503
Nov-90	1,149	131	2,809
Dec-90	72	8	136
Jan-91	384	44	726
Feb-91	460	53	870
Mar-91	395	44	994

Apr-91	0	0	0
May-91	250	24	1,107
Jun-91	996	99	4,415
Jul-91	847	84	3,755
Aug-91	858	85	3,804
Sep-91	789	78	3,499
Oct-91	328	35	5,360
Nov-91	156	24	3,319
Dec-91	171	24	4,072
Jan-92	168	22	4,144
Feb-92	208	8	3,995
Mar-92	92	16	2,609
Apr-92	25	4	697
May-92	0	0	0
Jun-92	0	0	0
Jul-92	16	2	458
Aug-92	369	18	3,821
Sep-92	144	5	1,851
Oct-92	350	12	4,515
Nov-92	1,095	34	3,578
Dec-92	463	48	5,274
Jan-93	343	49	5,676
Feb-93	317	45	5,239
Mar-93	368	52	6,095
Apr-93	292	41	4,834
May-93	116	16	1,915
Jun-93	518	57	6,127
Jul-93	730	74	5,704
Aug-93	519	49	3,995
Sep-93	427	41	3,930
Oct-93	173	18	3,853
Nov-93	2	0	38
Dec-93	103	10	2,292
Jan-94	70	5	1,565
Feb-94	282	21	6,270
Mar-94	218	15	4,846
Apr-94	508	4	9,413
May-94	803	100	9,235
Jun-94	755	134	8,681
Jul-94	677	77	7,790
Aug-94	777	96	8,937
Sep-94	751	81	8,635
Oct-94	848	105	9,752
Nov-94	244	30	2,801
Dec-94	792	92	9,103

Jan-95	1,109	112	12,754
Feb-95	1,051	127	12,083
Mar-95	763	109	11,330
Apr-95	407	33	8,785
May-95	560	54	12,111
Jun-95	188	18	4,067
Jul-95	351	34	7,574
Aug-95	477	46	10,297
Sep-95	479	46	10,342
Oct-95	492	47	10,621
Nov-95	487	47	8,646
Dec-95	543	52	8,070
Jan-96	447	43	6,636
Feb-96	0	0	0
Mar-96	0	0	0
Apr-96	22	2	322
May-96	0	0	0
Jun-96	0	0	0
Jul-96	0	0	0
Aug-96	40	4	600
Sep-96	372	36	5,527
Oct-96	490	47	7,283
Nov-96	490	47	7,282
Dec-96	0	0	0
Jan-97	420	40	6,235
Feb-97	379	36	5,625
Mar-97	634	61	9,423
Apr-97	235	23	3,493
May-97	241	23	3,582
Jun-97	484	47	7,188
Jul-97	503	48	7,474
Aug-97	344	33	5,116
Sep-97	528	51	2,718
Oct-97	987	95	3,692
Nov-97	670	64	2,509
Dec-97	539	52	2,019
Feb-98	281	27	1,052
Mar-98	263	25	984
Apr-98	0	0	0
May-98	147	14	550
Jun-98	89	9	333
Jul-98	275	26	1,029
Aug-98	916	88	3,430
Sep-98	775	75	2,900
Oct-98	812	78	3,039

Nov-98	663	64	2,481
Dec-98	405	39	1,514
Jan-99	192	18	718
Feb-99	195	19	733
Mar-99	182	18	683
Apr-99	168	16	631
May-99	97	9	361
Jun-99	0	0	0

A32

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
Oct-87	3,326	229	2,069
Nov-87	14,738	1,213	5,320
Dec-87	9,937	829	2,063
Jan-88	7,853	583	1,568
Feb-88	5,415	328	1,332
Mar-88	5,478	330	3,569
Apr-88	4,859	300	7,168
May-88	3,375	165	6,465
Jun-88	2,847	128	6,772
Jul-88	2,504	213	8,104
Aug-88	2,923	337	9,116
Sep-88	2,377	324	7,143
Oct-88	2,110	348	7,750
Nov-88	2,218	383	8,245
Dec-88	2,396	338	9,683
Jan-89	2,052	548	8,600
Feb-89	1,823	483	8,270
Mar-89	1,198	278	5,962
Apr-89	1,093	218	5,057
May-89	0	0	0
Jun-89	391	79	1,701
Jul-89	510	122	2,781
Aug-89	1,176	213	5,725
Sep-89	886	130	3,854
Oct-89	2,006	286	7,725
Nov-89	1,387	209	4,917
Dec-89	1,651	343	7,409
Jan-90	1,746	241	7,541
Feb-90	1,738	232	8,708
Mar-90	1,982	253	9,495
Apr-90	1,601	215	8,679

May-90	1,913	242	10,508
Jun-90	1,302	165	7,154
Jul-90	455	57	2,499
Aug-90	852	108	4,678
Sep-90	855	183	9,204
Oct-90	1,482	214	5,843
Nov-90	1,476	213	5,084
Apr-91	0	0	0
May-91	0	0	0
Jun-91	179	27	606
Jul-91	918	141	3,108
Aug-91	1,117	233	5,383
Sep-91	353	88	2,083
Oct-91	452	118	2,109
Nov-91	2,663	486	6,301
Dec-91	4,186	819	5,823
Jan-92	3,126	631	6,133
Feb-92	2,174	553	6,482
Mar-92	1,073	286	5,304
Apr-92	1,188	317	6,144
May-92	212	56	1,097
Jun-92	37	9	191
Jul-92	369	98	1,910
Aug-92	751	200	3,887
Sep-92	352	62	1,232
Oct-92	347	61	1,216
Nov-92	1,195	212	4,186
Dec-92	782	139	2,742
Jan-93	586	73	2,945
Feb-93	577	71	3,702
Mar-93	489	60	2,739
Apr-93	270	33	1,358
May-93	242	30	1,218
Jun-93	1,519	189	6,556
Jul-93	3,986	134	5,545
Aug-93	1,165	17	1,084
Sep-93	1,944	29	1,809
Oct-93	1,394	101	3,820
Nov-93	125	15	1,686
Dec-93	0	0	0
Jan-94	0	0	15
Feb-94	3	0	126
Mar-94	0	0	20
Apr-94	11	0	0
May-94	2	0	0

Jun-94	1	0	0
Jul-94	1	0	0
Aug-94	2	0	0
Sep-94	0	0	0
Oct-94	2	0	0
Nov-94	1	0	0
Dec-94	3	0	0
Jan-95	3	0	0
Feb-95	3	0	0
Mar-95	386	55	0
Apr-95	396	27	4,264
May-95	488	40	5,261
Jun-95	173	14	1,866
Jul-95	168	14	1,807
Aug-95	387	31	4,168
Sep-95	414	34	4,465
Oct-95	453	37	4,885
Nov-95	368	30	3,968
Dec-95	351	29	3,783
Jan-96	344	28	3,704
Feb-96	212	17	2,290
Mar-96	261	21	2,814
Apr-96	363	29	3,912
May-96	235	19	3,318
Jun-96	318	26	4,196
Jul-96	576	47	4,860
Aug-96	77	6	543
Sep-96	499	41	3,530
Oct-96	263	21	1,865
Nov-96	590	48	4,591
Dec-96	464	38	6,552
Jan-97	1,219	99	3,322
Feb-97	2,275	185	3,014
Mar-97	1,169	95	5,566
Apr-97	3,242	263	4,063
May-97	786	64	4,164
Jun-97	638	52	3,630
Jul-97	1,483	120	3,952
Aug-97	613	50	4,770
Sep-97	954	78	4,220
Oct-97	1,514	123	4,186
Nov-97	1,160	94	3,148
Dec-97	346	28	1,174
Feb-98	1,869	152	1,318
Mar-98	2,366	192	960

Apr-98	1,433	116	3,662
May-98	1,781	145	4,110
Jun-98	1,969	160	3,701
Jul-98	638	52	2,190
Aug-98	168	14	4,248
Sep-98	712	58	3,363
Oct-98	923	75	3,536
Nov-98	1,186	96	3,887
Dec-98	867	70	4,311
Jan-99	1,569	127	4,203
Feb-99	2,073	168	2,710
Mar-99	579	47	3,027
Apr-99	106	9	2,856
May-99	6	0	272
Jun-99	0	0	0

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Date	Oil Production m3	Gas Production Ksm3	Water Production m3
May-88	0	0	0
Jun-88	0	0	0
Jul-88	0	0	0
Aug-88	0	0	0
Sep-88	7,592	988	6,131
Oct-88	5,458	536	2,804
Nov-88	3,831	297	1,453
Dec-88	7,160	626	4,427
Jan-89	7,686	872	6,167
Feb-89	6,880	773	6,274
Mar-89	6,918	638	6,695
Apr-89	2,187	209	1,918
May-89	0	0	0
Jun-89	0	0	0
Jul-89	0	0	0
Aug-89	3	0	2
Sep-89	28	2	24
Oct-89	0	0	0
Apr-90	4,105	311	5,899
May-90	5,784	475	10,694
Jun-90	3,473	288	6,764
Jul-90	1,914	186	4,103
Aug-90	3,785	454	7,355
Sep-90	3,015	314	5,721

Oct-90	2,264	114	4,431
Nov-90	1,669	58	4,443
Dec-90	0	0	1
Jan-91	0	0	1
Feb-91	2	0	5
Apr-91	0	0	0
May-91	0	0	0
Jun-91	138	3	385
Jul-91	866	22	2,413
Aug-91	603	75	3,383
Sep-91	3,435	570	2,499
Oct-91	60	9	36
Nov-91	681	112	409
Dec-91	18	3	138
Jan-92	90	17	687
Feb-92	30	5	230
Mar-92	174	33	1,328
Apr-92	190	37	1,451
May-92	14	2	105
Jun-92	21	4	158
Jul-92	200	39	1,527
Aug-92	137	26	1,047
Sep-92	86	16	654
Oct-92	95	17	1,536
Nov-92	17	2	1,129
Dec-92	14	1	897
Jan-93	0	0	26
Feb-93	0	0	0
Mar-93	0	0	0
Apr-93	18	2	1,183
May-93	2	0	129
Jun-93	0	0	0
Jul-93	0	0	0
Aug-93	0	0	0
Sep-93	0	0	0
Oct-93	5	0	329
Nov-93	0	0	0
Dec-93	0	0	0
Jan-94	14	1	904

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Date	Oil Production m3	Gas Production Ksm3	Water Production m3

Oct-89	4,849	657	140
Nov-89	12,357	2,125	138
Dec-89	11,352	2,093	179
Jan-90	10,938	2,513	251
Feb-90	9,657	1,911	1,028
Mar-90	9,831	2,045	2,172
Apr-90	9,488	1,989	1,936
May-90	10,096	2,052	1,745
Jun-90	8,555	1,550	645
Jul-90	8,761	1,887	1,754
Aug-90	9,694	2,012	1,843
Sep-90	8,153	1,648	1,876
Oct-90	7,394	1,770	1,838
Nov-90	5,761	1,550	1,787
Dec-90	42	12	14
Jan-91	9	2	3
Feb-91	5	1	2
Mar-91	639	190	220
Apr-91	0	0	0
May-91	395	117	136
Jun-91	2,764	1,226	2,871
Jul-91	1,892	973	2,727
Aug-91	2,051	974	1,460
Sep-91	1,565	581	1,264
Oct-91	3,344	1,283	3,130
Nov-91	2,043	1,092	2,359
Dec-91	341	280	495
Jan-92	422	342	623
Feb-92	170	45	390
Mar-92	32	8	203
Apr-92	39	10	249
May-92	1	0	3
Jun-92	0	0	3
Jul-92	24	6	150
Aug-92	26	6	165
Sep-92	300	80	136
Oct-92	1,771	473	737
Nov-92	2,252	299	9,291
Dec-92	1,461	215	1,461
Jan-93	932	116	932
Feb-93	1,027	128	3,312
Mar-93	715	89	16,195
Apr-93	603	75	10,157
May-93	469	58	7,904
Jun-93	555	69	14,452

Jul-93	251	34	7,348
Aug-93	29	3	836

A41Z

Date	Oil Production m3	Gas Production Ksm3	Water Production m3
May-91	1,388	79	403
Jun-91	27,543	1,708	11,095
Jul-91	12,214	900	11,249
Aug-91	10,217	1,472	18,645
Sep-91	6,515	1,211	13,526
Oct-91	10,481	2,524	25,915
Nov-91	10,650	1,997	25,078
Dec-91	9,663	1,666	21,854
Jan-92	7,964	1,439	19,916
Feb-92	6,483	1,202	20,108
Mar-92	4,817	1,219	16,647
Apr-92	5,430	1,302	21,745
May-92	5,123	1,361	21,258
Jun-92	1,410	376	5,785
Jul-92	4,987	1,298	20,792
Aug-92	4,579	904	21,403
Sep-92	1,854	495	9,041
Oct-92	3,049	814	13,793
Nov-92	4,809	1,284	21,743
Dec-92	3,643	973	15,157
Jan-93	4,369	544	2,511
Feb-93	3,700	461	9,082
Mar-93	4,346	541	19,531
Apr-93	2,716	338	12,207
May-93	4,131	515	18,566
Jun-93	4,899	610	21,607
Jul-93	4,893	658	21,861
Aug-93	2,671	333	11,315
Sep-93	3,897	485	15,615
Oct-93	6,054	754	26,089
Nov-93	2,093	260	7,356
Dec-93	2,944	367	9,744
Jan-94	4,930	352	12,640
Feb-94	2,763	87	3,066
Mar-94	1,801	108	8,492
Apr-94	3,154	28	13,840
May-94	4,330	518	15,200

Jun-94	2,200	391	5,575
Jul-94	2,734	311	15,488
Aug-94	5,199	648	12,415
Sep-94	2,671	290	6,478
Oct-94	4,292	535	11,236
Nov-94	1,003	124	2,711
Dec-94	4,152	481	13,287
Jan-95	3,624	367	14,141
Feb-95	3,144	380	13,320
Mar-95	3,749	534	14,720
Apr-95	3,084	220	13,053
May-95	2,970	254	12,803
Jun-95	2,136	183	9,418
Jul-95	1,822	156	8,178
Aug-95	3,369	288	8,009
Sep-95	3,192	273	8,539
Oct-95	2,349	201	11,454
Nov-95	2,668	228	12,012
Dec-95	2,994	256	14,511
Jan-96	2,792	239	13,535
Feb-96	2,713	232	13,151
Mar-96	3,145	269	15,243
Apr-96	2,998	256	14,528
May-96	3,020	258	14,638
Jun-96	3,378	289	16,378
Jul-96	3,739	320	18,124
Aug-96	236	20	1,145
Sep-96	2,958	253	16,141
Oct-96	5,867	502	20,614
Nov-96	8,421	720	21,346
Dec-96	8,296	710	22,464
Jan-97	7,230	618	17,679
Feb-97	5,310	454	14,128
Mar-97	8,945	765	20,046
Apr-97	6,512	557	14,593
May-97	7,688	658	14,816
Jun-97	6,551	560	16,613
Jul-97	7,213	617	18,291
Aug-97	6,414	549	32,624
Sep-97	7,143	611	29,215
Oct-97	6,749	577	28,678
Nov-97	3,372	288	22,560
Dec-97	2,742	235	16,358
Feb-98	1,493	128	15,420
Mar-98	4,893	419	27,000

Apr-98	5,956	509	29,505
May-98	6,117	523	30,575
Jun-98	5,667	485	28,707
Jul-98	3,305	283	16,449
Aug-98	6,930	593	30,076
Sep-98	5,611	480	23,817
Oct-98	5,901	505	24,586
Nov-98	5,372	459	30,234
Dec-98	5,927	507	27,982
Jan-99	6,112	523	23,624
Feb-99	4,837	414	17,900
Mar-99	5,131	439	19,488
Apr-99	5,342	457	15,867
May-99	4,992	427	13,678
Jun-99	4,544	389	12,330

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Date	Oil Production m3	Gas Production Ksm3	Water Production m3
May-91	419	24	1,326
Jun-91	4,956	284	15,694
Jul-91	3,329	191	10,541
Aug-91	1,655	132	11,935
Sep-91	410	77	7,598
Oct-91	12	2	206
Nov-91	142	28	2,398
Dec-91	0	0	0
Jan-92	0	0	0
Feb-92	0	0	0
Mar-92	0	0	0
Apr-92	0	0	0
May-92	0	0	0
Jun-92	0	0	0
Jul-92	60	11	1,019
Aug-92	180	35	3,040
Sep-92	0	0	0
Oct-92	0	0	0
Nov-92	0	0	0
Dec-92	63	12	1,065
Jan-93	1	0	23
Feb-93	93	18	1,574
Mar-93	281	55	4,742
Apr-93	36	7	608

Water injection

A08Z

Date	Water injection m3
Aug-91	25836
Sep-91	52028
Oct-91	0
Nov-91	9252
Dec-91	6041
Jan-92	0
Feb-92	0
Mar-92	0
Apr-92	0
May-92	0
Jun-92	0
Jul-92	26740
Aug-92	11471
Sep-92	37089
Oct-92	27400
Nov-92	43649
Dec-92	33938
Jan-93	27974
Feb-93	23997
Mar-93	25606
Apr-93	36069
May-93	25180
Jun-93	16944
Jul-93	24726
Aug-93	1392
Sep-93	12736
Oct-93	20871
Nov-93	15772
Dec-93	20556
Jan-94	19172
Feb-94	11352
Mar-94	8814
Apr-94	2443
May-94	0
Jun-94	0
Jul-94	0
Aug-94	0
Sep-94	0
Oct-94	0
Nov-94	0
Dec-94	392

Jan-95	0
Feb-95	0
Mar-95	0
Apr-95	0
May-95	0
Jun-95	10575
Jul-95	11895
Aug-95	14819
Sep-95	10859
Oct-95	18804
Nov-95	9401
Dec-95	12286
Jan-96	3760
Feb-96	0
Mar-96	0
Apr-96	0
May-96	0
Jun-96	0
Jul-96	0
Aug-96	0
Sep-96	0
Oct-96	10230
Nov-96	24258
Dec-96	15537
Jan-97	5994
Feb-97	8106
Mar-97	10748
Apr-97	8467
May-97	2820
Jun-97	6
Jul-97	0
Aug-97	0
Sep-97	0
Oct-97	688476
Nov-97	18076
Dec-97	8329
Jan-98	372
Feb-98	10595
Mar-98	8201
Apr-98	0
May-98	11331
Jun-98	1290
Jul-98	0
Aug-98	0
Sep-98	0

Oct-98	0
Nov-98	0
Dec-98	0
Jan-99	0
Feb-99	0
Mar-99	0
Apr-99	0
May-99	0
Jun-99	0

A16

Date	Water injection m3
Dec-84	3539
Jan-85	3256
Feb-85	5237
Mar-85	4510
Apr-85	1632
May-85	3402
Jun-85	3450
Jul-85	35
Aug-85	5459
Sep-85	4853
Oct-85	9546
Nov-85	8375
Dec-85	6099
Jan-86	5617
Feb-86	4677
Mar-86	19938
Apr-86	28970
May-86	25711
Jun-86	26196
Jul-86	31939
Aug-86	28708
Sep-86	24407
Oct-86	26091
Nov-86	23089
Dec-86	24303
Jan-87	25489
Feb-87	13296
Mar-87	25990
Apr-87	18822
May-87	23110

Jun-87	26223
Jul-87	25599
Aug-87	25366
Sep-87	24481
Oct-87	25598
Nov-87	24948
Dec-87	26021
Jan-88	26219
Feb-88	23667
Mar-88	24550
Apr-88	22347
May-88	25152
Jun-88	24992
Jul-88	24782
Aug-88	32612
Sep-88	31732
Oct-88	31527
Nov-88	28144
Dec-88	37936
Jan-89	34905
Feb-89	20251
Mar-89	13879
Apr-89	10151
May-89	0
Jun-89	0
Jul-89	0
Aug-89	37
Sep-89	0
Oct-89	19
Nov-89	10448
Dec-89	20408
Jan-90	16825
Feb-90	15887
Mar-90	16361
Apr-90	15765
May-90	9940

A21

Date	**Water injection m3**
Mar-85	15546
Apr-85	34099
May-85	44545

Jun-85	30034
Jul-85	64391
Aug-85	66185
Sep-85	11849
Oct-85	39056
Nov-85	92005
Dec-85	89372
Jan-86	92088
Feb-86	77506
Mar-86	82890
Apr-86	93343
May-86	99244
Jun-86	92436
Jul-86	92378
Aug-86	110312
Sep-86	138695
Oct-86	137569
Nov-86	121964
Dec-86	126490
Jan-87	123366
Feb-87	52971
Mar-87	128449
Apr-87	118954
May-87	105335
Jun-87	122901
Jul-87	123740
Aug-87	123610
Sep-87	117191
Oct-87	120414
Nov-87	116356
Dec-87	119848
Jan-88	122019
Feb-88	105031
Mar-88	103972
Apr-88	108827
May-88	116388
Jun-88	109928
Jul-88	109668
Aug-88	7882
Sep-88	0
Oct-88	4
Nov-88	0
Dec-88	29721
Jan-89	110226
Feb-89	107543

Mar-89	80194
Apr-89	42619
May-89	0
Jun-89	0
Jul-89	83270
Aug-89	103214
Sep-89	39814
Oct-89	93099
Nov-89	90444
Dec-89	113017
Jan-90	100653
Feb-90	93259
Mar-90	89384
Apr-90	82568
May-90	49449
Jun-90	
Jul-90	
Aug-90	
Sep-90	
Oct-90	
Nov-90	
Dec-90	
Jan-91	
Feb-91	
Mar-91	
Apr-91	0
May-91	0
Jun-91	21408
Jul-91	66190
Aug-91	102545
Sep-91	81810
Oct-91	66889
Nov-91	39551
Dec-91	46863
Jan-92	52092
Feb-92	39896
Mar-92	27771
Apr-92	42710
May-92	43374
Jun-92	29443
Jul-92	70388
Aug-92	52084
Sep-92	6895
Oct-92	42560
Nov-92	62606

Dec-92	55794
Jan-93	50314
Feb-93	41492
Mar-93	36722
Apr-93	27766
May-93	50635
Jun-93	47267
Jul-93	48448
Aug-93	36191
Sep-93	38994
Oct-93	28243
Nov-93	47898
Dec-93	40229
Jan-94	47832
Feb-94	37432
Mar-94	44486
Apr-94	21205
May-94	0
Jun-94	0
Jul-94	0
Aug-94	0
Sep-94	0
Oct-94	22577
Nov-94	18126
Dec-94	33378
Jan-95	34189
Feb-95	34264
Mar-95	49318
Apr-95	54335
May-95	46338
Jun-95	20507
Jul-95	48764
Aug-95	18862
Sep-95	41287
Oct-95	49226
Nov-95	54129
Dec-95	49205
Jan-96	28759
Feb-96	2605
Mar-96	0
Apr-96	47737
May-96	44492
Jun-96	46521
Jul-96	49316
Aug-96	11410

Sep-96	48762
Oct-96	33776
Nov-96	48378
Dec-96	44160
Jan-97	42769
Feb-97	33618
Mar-97	46440
Apr-97	49152
May-97	43889
Jun-97	47649
Jul-97	42828
Aug-97	44576
Sep-97	47880
Oct-97	43109
Nov-97	46147
Dec-97	27704
Jan-98	0
Feb-98	38286
Mar-98	55947
Apr-98	47746
May-98	54474
Jun-98	47181
Jul-98	20970
Aug-98	47927
Sep-98	37684
Oct-98	60503
Nov-98	48293
Dec-98	5966
Jan-99	0
Feb-99	0
Mar-99	0
Apr-99	0
May-99	0
Jun-99	0